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Baroid Fluids Handbook Help

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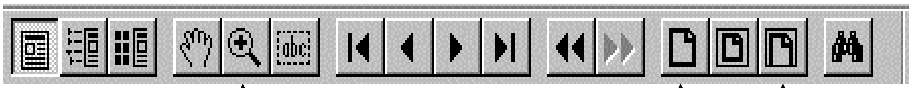

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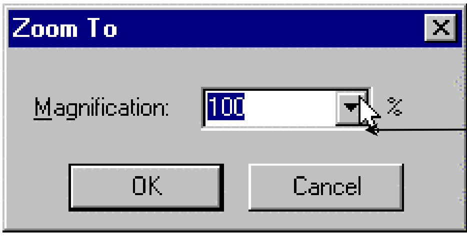

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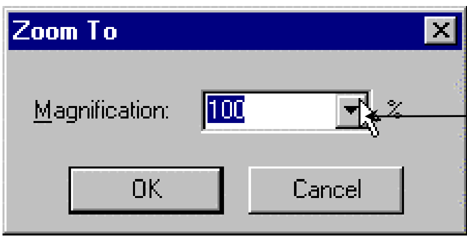

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CHAPTER 1

Completion fluids

Contents

Overview

Completion and workover fluids are used for their ability to not only control formation pressure, but also to reduce/eliminate certain types of formation damage. The two basic types of completion and workover systems are clear-fluid systems and solids-enhanced systems. This chapter covers each of these systems and provides information on selecting and handling completion and workover fluids.

Information on completion and workover fluids is also found in the following chapters:

- Corrosion
- Displacement
- Lost circulation

Clear-fluid systems

A clear-fluid system is the preferred completion or workover system because the properties of clear-fluid systems protect formations. In addition, clear-fluid systems make excellent packer fluids that can expedite workover operations.

Clear-fluid systems are solutions of various salts that are classified into two major groups: monovalent and divalent. Table 1-1 lists monovalent and divalent solutions.

Monovalent solutions	Divalent solutions
• Sodium chloride • Sodium bromide • Sodium formate • Potassium chloride • Potassium bromide • Potassium formate • Cesium formate	• Calcium chloride • Calcium bromide • Zinc bromide

Table 1-1: Monovalent and divalent solutions. Monovalent solutions contain sodium and potassium; divalent solutions contain calcium and zinc.

Clear-fluid system selection

When determining if a fluid will perform effectively in the planned completion or workover operation, consider the following factors:

- Density
- Crystallization point
- Brine/formation water compatibility
- Corrosion

Density

Clear brines are used in both underbalanced and overbalanced conditions. Frequently, a well is completed in an overbalanced situation and the heavy brine is replaced with a lighter packer fluid.

If a well is completed...	Then...
• In an *underbalanced* situation, • With an underbalanced packer fluid left in the well,	Casing design and cost are the main factors to consider when selecting a brine density and corresponding brine.
• In an *overbalanced* situation, • As a workover operation requiring a kill fluid,	The required density is determined by formation pressure, true vertical depth, and temperature gradient.

***Caution: Temperature has a significant effect on the weight of a column of brine fluid. Never calculate the required density for a brine without considering the effect of temperature. Refer to the downhole density correction calculation in the chapter titled* Tables, charts, and calculations.**

Figure 1-1 compares the density of clear-fluid systems.

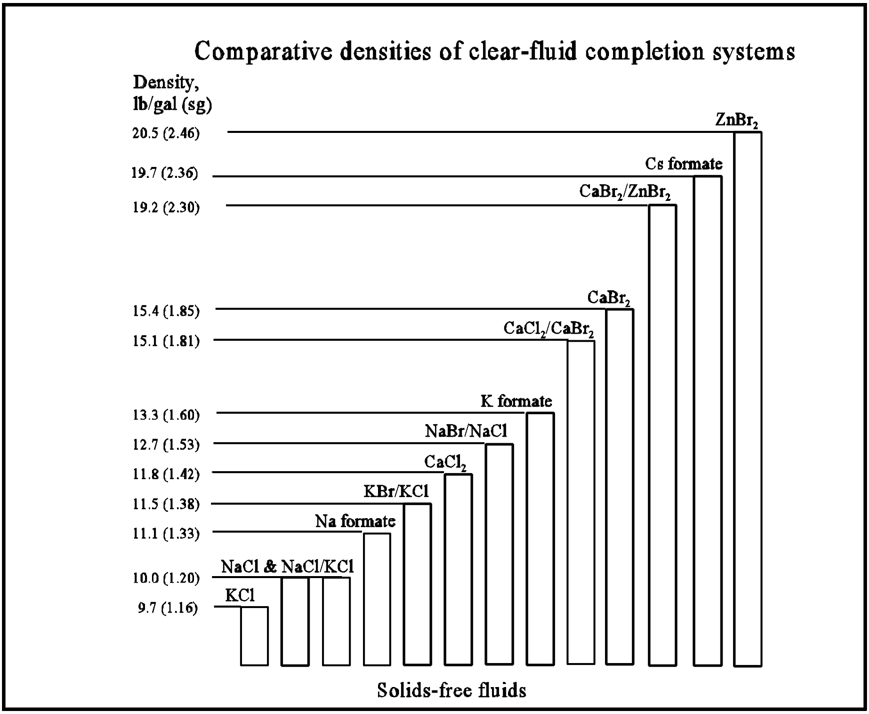

Figure 1-1: Comparative densities of clear-fluid completion systems.

Crystallization point

A brine's crystallization point is the temperature at which salt crystals will begin to fall out of solution given sufficient time and proper nucleating conditions.

Note: Nucleation is the process by which insoluble matter provides a physical platform upon which crystals can form.

The precipitation of insoluble salts can cause a number of problems. For example, when the dissolved salt in the fluid crystallizes and settles in a tank, the fluid density usually drops. Crystallization in brines can also cause lines to plug and pumps to seize.

To ensure crystallization does not occur in a brine:

- Determine the required crystallization point of the fluid
- Check the actual crystallization point of the fluid
- Adjust the crystallization point of the fluid, as necessary

The following paragraphs discuss how to determine, check, and adjust the crystallization point of a fluid.

Determining the required crystallization point. In choosing the lowest-cost formulation for a given density, consider the temperatures at which the brine will be transported, stored, and used. The crystallization point of a fluid should be a minimum of 10°F (6°C) less than the lowest projected temperature of exposure. For deep-water projects, consider the seawater temperature at the ocean floor.

Checking the actual crystallization point. Three temperature values are used to describe a fluid's crystallization point. These include the:

- First crystal to appear (FCTA)
- True crystallization temperature (TCT)
- Last crystal to dissolve (LCTD)

The TCT is the API-prescribed method for describing crystallization point; all temperature values can be determined at the wellsite using the brine-crystallization test kit. The procedure for determining a fluid's crystallization point is provided in the chapter titled *Field tests*.

Adjusting the crystallization point. Although fluid delivered to a wellsite is formulated to have the correct density and crystallization point for the well and weather conditions, it may be necessary to adjust the fluid's crystallization point. This is done by adding dry salts (e.g., $CaBr_2$ or $CaCl_2$), stock brines, (e.g., 14.2 lb/gal (1.70 sg) $CaBr_2$ or 19.2 lb/gal (2.30 sg) $Ca/ZnBr_2$), or water.

Adjusting a fluid's density using dry salts affects the fluid's crystallization point. For single-salt solutions, the addition of the same type of dry salt lowers the crystallization point of the solution down to the eutectic point, which is the lowest freezing point of a solution obtainable by increasing the concentration of a solute. For example, the addition of dry calcium chloride to water and calcium brines lowers the crystallization point of the brine solution until it reaches a density of 10.8 lb/gal (1.29 sg). Further, the addition of dry calcium chloride to a 10.8 lb/gal (1.29 sg) brine solution raises the crystallization point, even though the density continues to increase. For two-salt brines with a crystallization point of 30°F (-1°C), the addition of a dry salt in general raises the crystallization point.

The addition of fresh water to a single-salt brine whose density is above the eutectic point lowers the density and crystallization point.

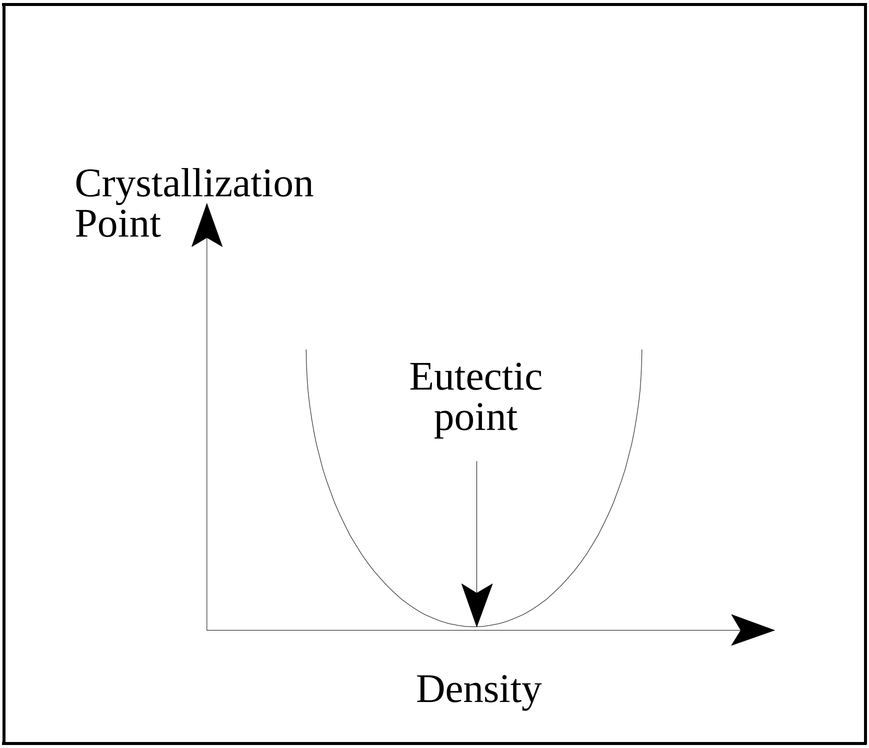

Figure 1-2: Eutectic point. The eutectic point is the lowest freezing point of a solution. This curve is not necessarily a symmetrical function.

The addition of fresh water to a two-salt system tends to lower the density and crystallization point. An estimate of the crystallization point for a blend of brines can be obtained by using the tables on pages 1-8 through 1-18. To accurately determine the crystallization point for a blend of brines, run a pilot test on the brine using the brine-crystallization test kit.

Brine/formation water compatibility

To select the correct brine type, consider the potential interactions of the completion or workover fluid with formation solids, water, and gases. The most common incompatibility problems include:

- Scale production from the reaction of a divalent brine with dissolved carbon dioxide
- Precipitation of sodium chloride from the formation water when it is exposed to certain brines
- Precipitation of iron compounds in the formation resulting from interaction with soluble iron in the completion fluid
- Reaction of formation clays with the clear brine

The following laboratory tests can be used to evaluate the compatibility of a clear fluid with a formation:

- Return permeability
- Formation water analysis
- Formation mineralogy
- Brine/water compatibility

For more information on laboratory tests, see the chapter titled *Specialized tests*.

Corrosion

The corrosivity of a completion or workover fluid depends on its type. Monovalent fluids generally show low corrosivity, even at temperatures exceeding 400°F (204°C). The corrosivity of divalent fluids depends on the density and chemical composition of the fluid. Laboratory data show that, for divalent fluids not treated with corrosion inhibitors, the addition of calcium chloride gives a slower rate of corrosion compared to that of zinc bromide which gives a faster rate of corrosion.

For more information on corrosive agents and their treatments, see the chapter titled *Corrosion*.

Brine formulations

The brine formulations in this section provide recommended solution requirements for the following:

- Sodium chloride
- Potassium chloride
- Calcium chloride
- Sodium bromide
- Sodium bromide/sodium chloride
- Calcium bromide
- Calcium bromide/calcium chloride

Note: The formulations are based on LCTD values, not TCT values.

Sodium chloride solution requirements to make 1 bbl (42 gal)

Using sacked NaCl (100%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)	Using 10.0 lb/gal NaCl brine	
Fresh water, bbl	100% NaCl, lb				Water, bbl	10 lb/gal NaCl, bbl
0.998	4	8.4	1.01	31 (-0.6)	0.96	0.04
0.993	9	8.5	1.02	29 (-1.7)	0.90	0.10
0.986	16	8.6	1.03	27 (-2.8)	0.84	0.16
0.981	22	8.7	1.04	26 (-3.3)	0.78	0.22
0.976	28	8.8	1.05	24 (-4.4)	0.72	0.28
0.969	35	8.9	1.07	22 (-5.6)	0.66	0.34
0.962	41	9.0	1.08	19 (-7.2)	0.60	0.40
0.955	47	9.1	1.09	17(-8.3)	0.54	0.46
0.948	54	9.2	1.10	14 (-10.0)	0.48	0.52
0.940	61	9.3	1.11	11 (-11.7)	0.42	0.58
0.933	68	9.4	1.13	9 (-12.8)	0.36	0.64
0.926	74	9.5	1.14	6 (-14.4)	0.30	0.70
0.919	81	9.6	1.15	3 (-16.1)	0.24	0.76

(continued on next page)

Sodium chloride solution requirements to make 1 bbl (42 gal)						
Using sacked NaCl (100%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)	Using 10.0 lb/gal NaCl brine	
Fresh water, bbl	100% NaCl, lb				Water, bbl	10 lb/gal NaCl, bbl
0.910	88	9.7	1.16	-1 (-18.3)	0.18	0.82
0.902	95	9.8	1.17	-5 (-20.5)	0.12	0.88
0.895	102	9.9	1.19	5 (-15.0)	0.06	0.94
0.888	109	10.0	1.20	25 (-3.9)	---	1.00

Table 1-2: Sodium chloride solution requirements. Dry sodium chloride or sodium chloride brine can be used to produce the required crystallization point (CP).

Potassium chloride solution requirements to make 1 bbl (42 gal)							
Using sacked KCl (100%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)	Potassium, ppm	Chloride, ppm	% by weight KCl
Fresh water, bbl	100% KCl, lb						
0.995	4.0	8.4	1.01	31 (-0.6)	005946	005392	1.1
0.986	11.6	8.5	1.02	29 (-1.7)	017041	015452	3.2
0.976	18.9	8.6	1.03	28 (-2-2)	027441	024882	5.2
0.969	26.1	8.7	1.04	26 (-3.3)	037460	033969	7.1
0.960	33.4	8.8	1.05	25 (-3.9)	047392	042976	9.1
0.950	40.7	8.9	1.07	23 (-5.0)	057102	051780	10.9
0.943	47.9	9.0	1.08	22 (-5.6)	066456	060263	12.7
0.933	55.2	9.1	1.09	20 (-6.7)	075743	068684	14.4
0.924	62.4	9.2	1.10	18 (-7.8)	084692	076799	16.1
0.917	69.7	9.3	1.11	16 (-8.9)	093582	084861	17.8
0.907	76.9	9.4	1.13	14 (-10.0)	102151	092631	19.5
0.898	84.2	9.5	1.14	18 (-7.8)	110671	100357	21.1
0.890	91.5	9.6	1.15	40 (4.4)	119013	107922	22.7
0.881	98.7	9.7	1.16	60 (15.6)	127054	115214	24.2

Table 1-3: Potassium chloride solution requirements. Dry potassium chloride can be added to produce the required crystallization point (CP).

Calcium chloride solution requirements to make 1 bbl (42 gal)						
Using sacked $CaCl_2$ (94-97%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)	Using 11.6 lb/gal $CaCl_2$ brine (38%)	
Fresh water, bbl	$CaCl_2$, lb				Fresh water, bbl	11.6 lb/gal $CaCl_2$, bbl
0.998	3.8	8.4	1.01	31 (-0.6)	0.979	0.021
0.997	8.2	8.5	1.02	30 (-1.1)	0.948	0.052
0.994	13.4	8.6	1.03	29 (-1.7)	0.917	0.083
0.991	18.7	8.7	1.04	27 (-2.8)	0.887	0.113
0.987	24.2	8.8	1.05	25 (-3.9)	0.856	0.144
0.984	29.4	8.9	1.07	24 (-4.4)	0.826	0.174
0.980	35.1	9.0	1.08	22 (-5.6)	0.795	0.205
0.977	40.5	9.1	1.09	20 (-6.7)	0.765	0.235
0.972	46.2	9.2	1.10	18 (-7.8)	0.734	0.266
0.968	52.0	9.3	1.11	15 (-9.4)	0.703	0.297
0.963	57.8	9.4	1.13	13 (-10.6)	0.673	0.327
0.959	63.4	9.5	1.14	10 (-12.2)	0.642	0.358
0.954	69.3	9.6	1.15	7 (-13.9)	0.612	0.388
0.949	75.4	9.7	1.16	4 (-15.6)	0.581	0.419
0.944	81.5	9.8	1.17	0 (-17.8)	0.550	0.450
0.939	87.4	9.9	1.19	-4 (-20.0)	0.520	0.480
0.934	93.2	10.0	1.20	-9 (-22.8)	0.489	0.511
0.929	99.3	10.1	1.21	-13 (-25.0)	0.459	0.541
0.923	105.4	10.2	1.22	-18 (-27.8)	0.428	0.572
0.918	111.3	10.3	1.23	-23 (-30.6)	0.398	0.602
0.912	117.6	10.4	1.25	-29 (-33.9)	0.367	0.633
0.908	123.5	10.5	1.26	-36 (-37.8)	0.336	0.640
0.902	129.8	10.6	1.27	-43 (-41.7)	0.306	0.694
0.895	136.3	10.7	1.28	-51 (-46.1)	0.275	0.725
0.891	142.0	10.8	1.29	-57 (-49.4)	0.245	0.755
0.885	148.3	10.9	1.31	-35 (-37.2)	0.214	0.786
0.878	155.0	11.0	1.32	-19 (-28.3)	0.183	0.817
0.872	161.3	11.1	1.33	-6 (-21.1)	0.153	0.847
0.866	167.6	11.2	1.34	7 (-13.9)	0.122	0.878
0.859	174.1	11.3	1.35	19 (-7.8)	0.092	0.908
0.853	180.4	11.4	1.37	27 (-2.8)	0.061	0.939
0.846	186.9	11.5	1.38	36 (2.2)	0.031	0.969
0.840	193.2	11.6	1.39	44 (6.7)	---	1.000

Table 1-4: Calcium chloride solution requirements. Dry calcium chloride or calcium chloride brine can be used to produce the required crystallization point (CP).

Sodium bromide solution requirements to make 1 bbl (42 gal)

Using sacked NaBr (95%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	95% NaBr, lb			
0.999	2.1	8.4	1.01	31 (-0.6)
0.996	7.6	8.5	1.02	30 (-1.1)
0.992	13.7	8.6	1.03	29 (-1.7)
0.989	19.2	8.7	1.04	29 (-1.7)
0.984	25.0	8.8	1.05	28 (-2.2)
0.979	31.0	8.9	1.07	26 (-3.3)
0.975	36.7	9.0	1.08	25 (-3.9)
0.970	42.6	9.1	1.09	24 (-4.4)
0.966	48.3	9.2	1.10	23 (-5.0)
0.961	54.2	9.3	1.11	22 (-5.6)
0.956	60.2	9.4	1.13	21 (-6.1)
0.950	66.4	9.5	1.14	20 (-6.7)
0.946	72.0	9.6	1.15	19 (-7.2)
0.941	77.9	9.7	1.16	18 (-7.8)
0.937	83.6	9.8	1.17	16 (-8.9)
0.933	89.2	9.9	1.19	15 (-9.4)
0.927	95.4	10.0	1.20	14 (-10.0)
0.923	101.1	10.1	1.21	12 (-11.1)
0.918	107.1	10.2	1.22	11 (-11.7)
0.914	112.6	10.3	1.23	10 (-12.2)
0.910	118.2	10.4	1.25	8 (-13.3)
0.905	124.1	10.5	1.26	6 (-14.4)
0.900	130.2	10.6	1.27	5 (-15.0)
0.895	136.0	10.7	1.28	4 (-15.6)
0.891	141.7	10.8	1.29	2 (-16.7)
0.886	147.6	10.9	1.31	0 (-17.8)
0.882	153.3	11.0	1.32	-2 (-18.8)
0.877	159.2	11.1	1.33	-3 (-19.4)
0.872	165.1	11.2	1.34	-5 (-20.6)
0.867	171.1	11.3	1.35	-7 (-21.7)
0.862	177.0	11.4	1.37	-9 (-22.8)
0.857	183.0	11.5	1.38	-11 (-23.9)
0.853	188.6	11.6	1.39	-14 (-25.6)
0.847	194.8	11.7	1.40	-16 (-26.7)

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Sodium bromide solution requirements to make 1 bbl (42 gal)				
Using sacked NaBr (95%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	95% NaBr, lb			
0.844	200.2	11.8	1.41	-19 (-28.3)
0.839	206.2	11.9	1.43	-10 (-23.3)
0.834	212.0	12.0	1.44	6 (-14.4)
0.831	217.3	12.1	1.45	14 (-10.0)
0.825	223.6	12.2	1.46	27 (-2.8)
0.823	228.5	12.3	1.47	34 (1.1)
0.816	235.1	12.4	1.49	43 (6.1)
0.812	240.7	12.5	1.50	50 (10.0)
0.807	246.7	12.6	1.51	57 (13.9)
0.804	252.0	12.7	1.52	63 (17.2)

Table 1-5: Sodium bromide solution requirements. Dry sodium bromide can be used to produce the required crystallization point (CP).

Sodium bromide/sodium chloride solution requirements to make 1 bbl (42 gal)						
Using 10.0 lb/gal NaCl, 12.3 lb/gal NaBr, and sacked (95%) NaBr				Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	10 lb/gal NaCl, bbl	12.3 lb/gal NaBr, bbl	95% NaBr, lb			
0.982	---	0.018	---	8.4	1.01	31 (-0.6)
0.957	---	0.043	---	8.5	1.02	30 (-1.1)
0.932	---	0.068	---	8.6	1.03	29 (-1.7)
0.907	---	0.093	---	8.7	1.04	29 (-1.7)
0.882	---	0.118	---	8.8	1.05	28 (-2.2)
0.856	---	0.144	---	8.9	1.07	26 (-3.3)
0.831	---	0.169	---	9.0	1.08	25 (-3.9)
0.806	---	0.194	---	9.1	1.09	24 (-4.4)
0.781	---	0.219	---	9.2	1.10	23 (-5.0)
0.756	---	0.244	---	9.3	1.11	22 (-5.6)
0.730	---	0.270	---	9.4	1.13	21 (-6.1)
0.705	---	0.295	---	9.5	1.14	20 (-6.7)
0.680	---	0.320	---	9.6	1.15	19 (-7.2)
0.655	---	0.345	---	9.7	1.16	18 (-7.8)
0.630	---	0.370	---	9.8	1.17	16 (-8.9)
0.605	---	0.395	---	9.9	1.19	15 (-9.4)
0.579	---	0.421	---	10.0	1.20	14 (-10.0)
---	0.957	0.043	---	10.1	1.21	25 (-3.9)
---	0.913	0.087	---	10.2	1.22	26 (-3.3)
---	0.870	0.130	---	10.3	1.23	26 (-3.3)
---	0.826	0.174	---	10.4	1.25	27 (-2.8)
---	0.782	0.218	---	10.5	1.26	27 (-2.8)
---	0.739	0.261	---	10.6	1.27	27 (-2.8)
---	0.696	0.304	---	10.7	1.28	28 (-2.2)
---	0.652	0.348	---	10.8	1.29	28 (-2.2)
---	0.609	0.391	---	10.9	1.31	29 (-1.7)
---	0.565	0.435	---	11.0	1.32	29 (-1.7)
---	0.522	0.478	---	11.1	1.33	29 (-1.7)
---	0.478	0.522	---	11.2	1.34	30 (-1.1)
---	0.435	0.565	---	11.3	1.35	30 (-1.1)
---	0.391	0.609	---	11.4	1.37	31 (-0.6)
---	0.348	0.652	---	11.5	1.38	31 (-0.6)
---	0.304	0.696	---	11.6	1.39	31 (-0.6)

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Sodium bromide/sodium chloride solution requirements to make 1 bbl (42 gal)						
Using 10.0 lb/gal NaCl, 12.3 lb/gal NaBr, and sacked (95%) NaBr				Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	10 lb/gal NaCl, bbl	12.3 lb/gal NaBr, bbl	95% NaBr, lb			
---	0.261	0.739	---	11.7	1.40	32 (0.0)
---	0.217	0.783	---	11.8	1.41	32 (0.0)
---	0.174	0.826	---	11.9	1.43	32 (0.0)
---	0.130	0.870	---	12.0	1.44	33 (0.6)
---	0.087	0.913	---	12.1	1.45	33 (0.6)
---	0.043	0.957	---	12.2	1.46	33 (0.6)
---	---	1.000	---	12.3	1.47	34 (1.1)
---	---	0.996	6.6	12.4	1.49	43 (6.1)
---	---	0.993	12.2	12.5	1.50	50 (10.0)
---	---	0.989	18.2	12.6	1.51	57 (13.9)
---	---	0.986	23.5	12.7	1.52	63

Table 1-6: Sodium bromide/sodium chloride solution requirements. Solutions of sodium chloride or sodium bromide can be used to produce the required crystallization point. To achieve the highest crystallization points, use dry sodium bromide.

Calcium bromide solution requirements to make 1 bbl (42 gal)				
Using sacked $CaBr_2$ (95%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	95% $CaBr_2$, lb			
0.822	197	11.7	1.40	-19 (-28.3)
0.817	203	11.8	1.41	-23 (-30.6)
0.811	210	11.9	1.43	-25 (-31.7)
0.806	216	12.0	1.44	-28 (-33.3)
0.801	222	12.1	1.45	-30 (-34.4)
0.795	228	12.2	1.46	-34 (-36.7)
0.790	233	12.3	1.47	-36 (-37.8)
0.784	240	12.4	1.49	-40 (-40.0)
0.778	247	12.5	1.50	-44 (-42.2)
0.773	252	12.6	1.51	-47 (-43.9)
0.767	259	12.7	1.52	-52 (-46.7)
0.762	265	12.8	1.53	-55 (-48.3)
0.756	272	12.9	1.55	-61 (-51.7)
0.750	277	13.0	1.56	-63 (-52.8)
0.746	282	13.1	1.57	-66 (-54.4)
0.739	290	13.2	1.58	-71 (-57.2)
0.732	298	13.3	1.59	-76 (-60.0)
0.728	302	13.4	1.61	-79 (-61.7)
0.723	308	13.5	1.62	-81 (-62.8)
0.717	315	13.6	1.63	-81 (-62.8)
0.711	322	13.7	1.64	-81 (-62.8)
0.704	328	13.8	1.65	-81 (-62.8)
0.699	334	13.9	1.67	-80 (-62.2)
0.692	342	14.0	1.68	-50 (-45.5)
0.687	348	14.1	1.69	-40 (-40.0)
0.681	354	14.2	1.70	5 (-15.0)
0.676	360	14.3	1.71	10 (-12.2)
0.669	368	14.4	1.73	23 (-5.0)
0.662	376	14.5	1.74	35 (1.7)
0.655	383	14.6	1.75	37 (2.8)
0.651	388	14.7	1.76	44 (6.7)
0.645	394	14.8	1.77	51 (10.6)
0.640	400	14.9	1.79	56 (13.3)
0.637	405	15.0	1.80	60 (15.6)

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Calcium bromide solution requirements to make 1 bbl (42 gal)				
Using sacked $CaBr_2$ (95%)		Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
Fresh water, bbl	95% $CaBr_2$, lb			
0.632	410	15.1	1.81	65 (18.3)
0.626	415	15.2	1.82	70 (21.1)
0.621	421	15.3	1.83	76 (24.4)
0.616	427	15.4	1.85	79 (26.1)
0.611	433	15.5	1.86	81 (27.2)

Table 1-7: Calcium bromide solution requirements. Dry calcium bromide can be used to produce the required crystallization point (CP).

Calcium bromide/calcium chloride solution requirements to make 1 bbl (42 gal)					
Using 11.6 lb/gal $CaCl_2$, 14.2 lb/gal $CaBr_2$, and sacked $CaCl_2$ (94-97%)			Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
11.6 lb/gal $CaCl_2$, bbl	14.2 lb/gal $CaBr_2$, bbl	Sacked $CaCl_2$ (94-97%), lb			
0.9714	0.0254	2.86	11.7	1.40	45 (7.2)
0.9429	0.0507	6.06	11.8	1.41	51 (10.6)
0.9143	0.0768	9.09	11.9	1.43	52 (11.1)
0.8857	0.1016	12.13	12.0	1.44	54 (12.2)
0.8572	0.1269	15.15	12.1	1.45	55 (12.8)
0.8286	0.1524	18.18	12.2	1.46	55 (12.8)
0.8000	0.1778	21.22	12.3	1.47	56 (13.3)
0.7715	0.2032	24.24	12.4	1.49	56 (13.3)
0.7429	0.2286	27.28	12.5	1.50	57 (13.9)
0.7143	0.2540	30.31	12.6	1.51	57 (13.9)
0.6847	0.2794	33.34	12.7	1.52	58 (14.4)
0.6472	0.3048	36.37	12.8	1.53	58 (14.4)
0.6286	0.3302	39.41	12.9	1.55	59 (15.0)
0.6000	0.3556	42.44	13.0	1.56	59 (15.0)
0.5714	0.3810	45.47	13.1	1.57	60 (15.6)
0.5429	0.4064	48.49	13.2	1.58	60 (15.6)
0.5143	0.4318	51.53	13.3	1.59	60 (15.6)
0.4857	0.4572	54.56	13.4	1.61	61 (16.1)
0.4572	0.4826	57.59	13.5	1.62	61 (16.1)
0.4286	0.5080	60.62	13.6	1.63	62 (16.7)
0.4000	0.5334	63.66	13.7	1.64	62 (16.7)
0.3714	0.5589	66.69	13.8	1.65	63 (17.2)
0.3429	0.5842	69.72	13.9	1.67	63 (17.2)
0.3143	0.6069	72.75	14.0	1.68	64 (17.8)
0.2857	0.6351	75.78	14.1	1.69	64 (17.8)
0.2572	0.6604	78.81	14.2	1.70	64 (17.8)
0.2286	0.6858	81.84	14.3	1.71	65 (18.3)
0.2000	0.7113	84.88	14.4	1.73	65 (18.3)
0.1715	0.7366	87.90	14.5	1.74	65 (18.3)
0.1429	0.7620	90.94	14.6	1.75	66 (18.9)
0.1143	0.7875	93.97	14.7	1.76	66 (18.9)
0.0858	0.8128	96.99	14.8	1.77	67 (19.4)

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Calcium bromide/calcium chloride solution requirements to make 1 bbl (42 gal)					
Using 11.6 lb/gal $CaCl_2$, 14.2 lb/gal $CaBr_2$, and sacked $CaCl_2$ (94-97%)			Brine density at 70°F (21°C), lb/gal	Specific gravity, sg	CP (LCTD) °F (°C)
11.6 lb/gal $CaCl_2$, bbl	14.2 lb/gal $CaBr_2$, bbl	Sacked $CaCl_2$ (94-97%), lb			
0.0572	0.8382	100.03	14.9	1.79	67 (19.4)
0.0286	0.8637	103.06	15.0	1.80	67 (19.4)
0.0000	0.8891	106.10	15.1	1.81	68 (20.0)

Table 1-8: Calcium bromide/calcium chloride solution requirements. Solutions of calcium chloride brine, dry calcium chloride, and calcium bromide can be used to produce the required crystallization point (CP).

Solids-enhanced fluids

A solids-enhanced fluid is recommended for completion or workover operations when the use of a clear brine would result in the loss of large fluid volumes to the formation.

The additive BARACARB is used to enhance completion fluid systems. BARACARB, a sized calcium carbonate, is acid-soluble. It can be used in systems with densities from 9.0 to 14.5 lb/gal (1.08 to 1.74 sg). Table 1-9 outlines the formulations of sized-calcium carbonate systems that contain BARACARB.

Additive	Function	Concentration, lb/bbl (kg/m^3)
Brine (monovalent)	Density	As needed
BARAZAN D PLUS	Suspension	0.5-1 (1.4-3)
DEXTRID	Filtration	4-6 (11-17)
PAC-R	Filtration	1 (3)
Caustic potash	pH	0.05 (0.15)
BARACARB	Plugging	min. of 30 (86)

Table 1-9: Sized-calcium carbonate system formulations. BARACARB is the main additive in a sized-calcium carbonate system; each additive has its own function and concentration.

Note: BARACARB comes in various grind sizes, such as 5, 25, 50 and 150 microns. When formulating a fluid for lost circulation in payzones, the average median particle size of the added solids should be one-third the diameter of the pore throat.

Contaminants

Contaminants that can affect completion and workover fluids include:

- Iron
- Solids
- Hardness
- Oil, distillate, grease, and pipe dope
- Polymers
- Surfactants

This section discusses these contaminants and their treatments. For information on how to prevent certain types of contamination, see the section titled *Handling fluids*.

Iron

Iron can be a contaminant in either soluble or insoluble form. Soluble iron is a product of corrosion and is common in zinc fluids. When exposed to certain waters, soluble iron can form a precipitate, which can cause formation damage. The soluble iron content of a fluid can be measured using the iron test kit described in the chapter titled *Field tests*.

Note: No brine should be delivered to location with an iron content greater than 75 ppm. Consider displacing a brine when its iron content reaches 625 ppm.

At the brine plant, iron should be removed from a fluid by adding hydrogen peroxide to the fluid, flocculating the fluid, then filtering the fluid. On location, treating a fluid for iron is very difficult and is usually successful only in low-density brines such as KCl, NaCl, or $CaCl_2$. The treatment consists of increasing pH with caustic or lime and removing the precipitated iron by filtering the brine.

Solids

Total solids can be measured at the wellsite using a turbidity meter (see the chapter titled *Field tests*) or a shake-out machine. Solids that are not added to the system to enhance the performance of a brine are considered contaminants. Contaminants include formation clays, precipitates, and polymer residues, among other things. These contaminants can be filtered at the wellsite using diatomaceous earth, a plate and frame press, and two-micron absolute cartridges.

Note: A clear completion fluid should not be sent to the wellsite with an NTU (Nephelometric Turbidity Unit) greater than 40 or a suspended-solids concentration greater than 50 ppm.

Hardness

When a monovalent brine has been selected to minimize calcium and magnesium scale formation, the total hardness content should not exceed 100 mg/L. Brines contaminated in the plant should be treated with soda ash and/or BARASCAV and filtered. To settle the precipitate prior to filtration, a flocculant might be needed.

Oil, distillate, grease, and pipe dope

Produced oils and other hydrocarbons affect brine density and can also blind filtration units. Hydrocarbons will form a separate layer above heavy brine and should be pumped off the surface.

Polymers

Brines contaminated with polymers usually cannot be filtered without chemical and/or special mechanical treatment at the plant site where hydrogen peroxide can be used to oxidize polymers and permit filtration. At the wellsite, polymer pills used in displacement should be caught and isolated from the active brine system.

Surfactants

Compatibility tests and formation damage tests should be run with any surfactant package required for completion.

Handling fluids

A completion or workover fluid should be protected from contamination while the fluid is prepared, transported, and used at the rig; any contamination can have costly results. Some brines are quite corrosive to the skin and eyes. All rig personnel who might come in

contact with these fluids must be trained in both handling fluid and personal safety.

Transporting fluids

To help maintain the quality of brines during transport:

- Ensure the boat or truck is clean and dry before loading the brine.
- Tie the fluid-transfer hose securely and continually monitor the hose for leaks or breaks.
- Ensure all brine is transferred to the boat or truck, including the brine in trip tanks, sand traps, cement-unit tanks, filter-unit tanks, slugging pits, etc.
- Strap the boat or truck tanks and check the density of the brine being shipped to help explain any losses in density and/or gains or losses in volume once the material is received.
- Ensure all hatches and valves on the boat or truck are securely closed before leaving the rig.
- Instruct the person in charge of transport not to transfer any fluid on board during transport.

Note: Major losses of volume often occur because some rig pits and boat tanks do not allow for the transfer of all fluid. When this is the case, consider renting a small, portable pump or modifying the rig pits.

Preparing the rig and rig housekeeping

Ensuring a successful completion or workover operation requires following certain precautions to help prevent fluid loss due to contamination and equipment leaks.

Before receiving fluid

- Cover all open pits to be used in handling the completion fluid. A solid, raised cover with sufficient overhang is preferable to tarps to keep rain water out of brine.
- Wash and dry all pits or tanks to be used in handling the fluid.

- Flush all lines and pumps with sea water or fresh water.
- Clean and dry the mud-return ditch, shale shaker, possum belly, and sand trap beneath the shale shaker.
- Seal return-ditch gates, shale-shaker gates, and dump valves by caulking with silicon compound or some other compatible material.
- Disconnect or plug all water and diesel lines leading to pits.
- Tie down the fluid-delivery hose to prevent accidents or loss of expensive fluid.
- Conduct a meeting to establish the methods for emergency communication with boat or truck personnel to allow for rapid shutdown of fluid transfer should problems develop.

While receiving fluid

- Monitor the delivery hose for breaks or leaks.
- Monitor pits and dump valves for leaks.
- Maintain communications with the boat or truck for estimated volumes pumped.
- Allow plenty of time to shut down delivery as soon as pits are full.

After receiving fluid

- Mark the fluid level in pits and monitor for losses.
- Inspect pits and dump valves for leaks.
- Use completion fluid to flush sea or fresh water from all lines, pumps, solids-control equipment, and degassers.

During completion or workover operations

- Monitor fluid level in pits and dump valves for losses.
- Monitor pits for accidental water additions.
- Restrict the use of pipe dope to a light coating on pin ends only.

Note: Clean and clear completion fluids do not contain solids that might plug a productive formation. Pits and lines must also be clean of solids. A pin hole plugged with mud solids can become unplugged, resulting in the loss of expensive fluid. Immediately investigate any unexplained loss of volume.

Personal safety

Safety is important when workers handle completion or workover fluids. To ensure a successful operation, observe the following basic recommendations:

- Prior to receiving the fluid, conduct a job-specific safety meeting with all personnel including those (such as production personnel) not directly involved in the completion/workover operation. At this safety meeting, review the safety video tape available through Baroid.
- Install eye-wash and shower stations in all areas where contact with the fluid is a possibility. At a minimum, eye-wash stations should be installed in the following areas:
  - — Rig floor (two or more locations)
  - — Mud pit (as needed for easy access)
  - — Mixing-hopper area
  - — High pressure pump service skid unit
  - — Production deck (under fluid-handling areas)
- Provide appropriate eye-protection devices to all personnel working near fluid-handling areas and require the use of eye-protection devices.
- Provide slicker suits, rubber gloves, rubber boots, and barrier cream to all personnel who will be working in fluid-handling areas or who might come in contact with the fluid.

If brine comes into contact with eyes or skin, or if ingestion or inhalation is suspected, take the following first-aid measures:

- **Eyes.** Flush eyes promptly with plenty of water for fifteen minutes. Get medical attention.
- **Skin.** Flush skin with plenty of water for fifteen minutes. If necessary, wash skin with soap.
- **Ingestion.** Consult the material safety data sheet for response information and get medical attention.

Note: Environmental regulations vary, and it is important to acquire the specific guidelines for the area where the brine will be used. It is mandatory that compliance with the regulations be carried out.

CHAPTER 2

Corrosion

Contents

Overview

This chapter covers how to treat drilling fluids, packer fluids, and completion/workover fluids for corrosion. A troubleshooting chart and a quick-reference list of products for inhibiting corrosion appear at the end of this chapter.

Corrosion is the destruction of metal through electrochemical action between metal and its environment. Corrosion can be costly in terms of damage to pipe and well parts and can even result in the loss of an entire well. About 75 to 85 percent of drillpipe loss can be attributed to corrosion. Other areas affected by corrosion include pump parts, bits, and casing. Factors affecting corrosion include:

- **Temperature.** Generally, corrosion rates double with every 55°F (31°C) increase in temperature.
- **Velocity.** The higher the mud velocity, the higher the rate of corrosion due to film erosion (oxide, oil, amine, etc.).
- **Solids.** Abrasive solids remove protective films and cause increased corrosive attack.
- **Metallurgical factors.** Mill scale and heat treatment of pipe can cause localized corrosion.
- **Corrosive agents.** Corrosive agents such as oxygen, carbon dioxide, and hydrogen sulfide can increase corrosion and lead to pipe failure.

The corrosion that occurs because of these various factors falls into three categories as shown in Table 2-1.

Category	Explanation
Uniform corrosion	Even corrosion pattern over surfaces
Localized corrosion	Mesa-like corrosion pattern over surfaces
Pitting	Highly localized corrosion that results in the deep penetration of surfaces

Table 2-1: Corrosion categories. The categories of corrosion range from uniform corrosion to mechanical damage.

Drilling-fluid corrosive agents

Corrosive agents found in drilling fluids include:

- Oxygen
- Hydrogen sulfide
- Carbon dioxide
- Bacteria
- Dissolved salts
- Mineral scale

Oxygen

Oxygen causes a major portion of corrosion damage to drilling equipment. Oxygen acts by removing protective films; this action causes accelerated corrosion and increased pitting under deposits. The four primary sources of oxygen are:

- Water additions
- Actions of mixing and solids-control equipment
- Aerated drilling fluids
- The atmosphere

Water additions. Water added to drilling mud during normal drilling operations can contain dissolved oxygen. Very small concentrations of oxygen (<1 ppm) can cause severe corrosion by setting up differential aeration cells that can show preferential attack with pitting under barriers or deposits. The primary

corrosion by-product of low oxygen concentrations is magnetite. The products recommended for the removal of dissolved oxygen are:

- BARASCAV L
- BARASCAV D

Actions of mixing and solids-control equipment. Mixing and solids-control equipment cause aeration of the drilling fluid during drilling operations. For example, aeration occurs as mud falls through the shaker screen or when hopper or mud guns are discharged above the surface of the mud in the pits. To reduce the amount of oxygen introduced into drilling fluid by mixing and solids-control equipment, follow these guidelines:

- Use a premix tank to mix mud, when possible.
- Operate mud-mixing pumps, especially the hopper, only when mixing mud.
- Keep the packing tight on centrifugal pumps.
- Ensure the mud in the suction pit is deep enough to keep the mud pump from pulling in air.
- Keep discharge below the mud surface when moving mud from the reserve pit.
- Ensure guns discharge below the mud surface; do not allow the mud-stirring device to create a vortex.
- Ensure the degasser and desander discharges are below the mud surface.

The products recommended for treating drilling fluid containing oxygen because of mixing and solids-control equipment are:

- BARASCAV L
- BARASCAV D

Aerated drilling fluids. While conventional drilling fluids require the removal of oxygen, aerated drilling (foam and mist drilling) fluids require the use of passivating (oxidizing) inhibitors to combat corrosion due to oxygen. The product recommended for inhibiting oxygen in aerated drilling fluids is BARACOR 700.

The atmosphere. The atmosphere is another source of oxygen, and hence corrosion. The main by-product of atmospheric corrosion is iron oxide rust. To prevent atmospheric corrosion, wash the pipe free of all salts and mud products and then spray or dip the pipe in an atmospheric corrosion inhibitor. The product recommended for inhibiting atmospheric corrosion is BARAFILM.

Hydrogen sulfide

Hydrogen sulfide can enter the mud system from:

- Formation fluids containing hydrogen sulfide
- Bacterial action on sulfur-containing compounds in drilling mud
- Thermal degradation of sulfur-containing drilling-fluid additives
- Chemical reactions with tool-joint thread lubricants containing sulfur

Hydrogen sulfide is soluble in water. Dissolved hydrogen sulfide behaves as a weak acid and causes pitting. Hydrogen ions at the cathodic areas may enter the steel instead of evolving from the surface as a gas. This process can result in hydrogen blistering in low-strength steels or hydrogen embrittlement in high-strength steels. Both the hydrogen and sulfide components of hydrogen sulfide can contribute to drillstring failures.

Hydrogen sulfide corrosion is mitigated by increasing the pH to above 9.5 and by using sulfide scavengers and film-forming inhibitors. The products recommended for combating corrosion due to hydrogen sulfide are:

- BARACOR 44 (zinc oxide)
- BARACOR 700
- NO-SULF (zinc carbonate)
- BARAFILM

The chapter titled *Tables, charts, and calculations* contains a formula for determining the amount of product to add in treating against this corrosive agent.

Note: Hydrogen sulfide and carbon dioxide are often encountered in the same geologic formation; therefore, design treatments to deal with both contaminants simultaneously. Ensure that well hydrostatic pressures are sufficient to prevent further influxes of gases. See Carbon dioxide *below.*

Carbon dioxide

Carbon dioxide is found in natural gas in varying quantities. When combined with water, carbon dioxide forms carbonic acid and decreases the water's pH, which increases the water's corrosivity. While carbon dioxide is not as corrosive as oxygen, it can cause pitting.

Maintaining the correct pH is the primary treatment for carbon dioxide contamination. Either lime or caustic soda can be used to maintain pH.

Table 2-2 provides the reactions for each of these treatments.

Treatment	Reaction
Caustic soda	2 $NaOH+CO_2+H_2O$ 2 $H_2O+Na_2CO_3$
Lime	$Ca(OH)_2+CO_2+H_2O$ 2 $H_2O+CaCO_3$

Table 2-2: Carbon dioxide treatments and reactions. This table shows the reactions resulting from caustic soda or lime treatment for carbon dioxide.

Treatment with caustic soda produces sodium carbonate, which is soluble and can create mud problems. Treatment with lime, on the other hand, produces an insoluble calcium carbonate precipitate and water.

Note: To maintain pH in water-based muds, consider using BARACOR 95 instead of lime. BARACOR 95 is a liquid amine compound that serves as a carbon-dioxide scavenger. This treatment is particularly useful with a polymeric system that may be pH-sensitive. When selecting BARACOR 95, keep in mind that it does not treat for hydrogen sulfide.

In addition to maintaining pH, use BARAFILM (filming amine inhibitor) to mitigate corrosion caused by carbon dioxide.

Note: Hydrogen sulfide and carbon dioxide are often encountered in the same geologic formation; therefore, design treatments to deal with both contaminants simultaneously. Ensure that well hydrostatic pressures are sufficient to prevent further influxes of gases. *See the section titled* Hydrogen sulfide.

Bacteria

Microorganisms can cause fermentation of organic mud additives, changing viscosity and lowering pH. A sour odor and gas are other indicators that bacteria are present. Degradation of mud additives can result in increased maintenance costs.

The by-products of bacteria are carbon dioxide and hydrogen sulfide. The presence of aerobic bacteria is determined by the phenol-red serum test. The presence of anaerobic bacteria is determined by the marine anaerobic serum test. These tests are discussed in the chapter titled *Specialized tests*. Microbiocides are used to control bacteria in drilling environments. The products recommended for controlling bacteria are:

- ALDACIDE G
- Isothiazolone-based biocide powder

Dissolved salts

Dissolved salts increase corrosion by decreasing the electrical resistance of drilling fluids and increasing the solubility of corrosion by-products. Some of these by-products can cause a scale or film to form on the surface of the metal. The products recommended for combating the effects of dissolved salts are:

- BARACOR 700
- BARAFILM

Mineral scale

Mineral scale deposits set up conditions for local corrosion-cell activity. The continuous addition of a scale inhibitor can control the formation of scale deposits. The product recommended for inhibiting the formation of scale deposits is STABILITE.

Packer-fluid treatments

When using a drilling fluid as a packer fluid, the drilling fluid must be conditioned to minimize corrosion under long-term, static conditions. Table 2-3 provides recommended treatments for various packer-fluid systems.

Packer-fluid system	Recommended treatment
Water-based mud	• Increase pH to between 9.5-11.5. • Add 2-4 lb/bbl (6-11 kg/m^3) BARACOR 44 or NO-SULF to control hydrogen sulfide. • Add a biocide to control bacteria.
Clear fresh water Clear salt water	• Add BARACOR 100 (0.5-1% by volume).
Oil or diesel	• Add BARAFILM (0.35% by volume).
Oil-based mud (diesel, mineral)	• Add 2-10 lb/bbl (6-29 kg/m^3) primary emulsifier and 2-10 lb/bbl (6-29 kg/m^3) GELTONE II/V. • Add 4-6 lb/bbl (11 -17 kg/m^3) lime.
Heavy brine ($CaCl_2$, $CaBr_2$, $ZnBr_2$, or blends of the three)	• Add BARACOR 100, 0.5-2% by volume or BARACOR 450, 0.2-0.4% by weight.

Table 2-3: Packer-fluid system treatments. To minimize corrosion under long-term, static conditions, follow the recommended treatment.

Completion/workover fluids

The corrosivity of a given completion or workover fluid depends on its brine type. Brines fall into two categories: monovalent and divalent.

Monovalent brines

Monovalent brines contain salts that have monovalent cations; these salts include sodium chloride, potassium chloride, potassium bromide, sodium bromide, sodium

formate, and potassium formate. Potassium bromide and sodium bromide are especially effective in calcium-sensitive formations and in formations where carbon dioxide gas might react with calcium brines to create a calcium-carbonate precipitate.

Monovalent brines generally show low corrosivity, even at temperatures exceeding 400°F (204°C).

Divalent brines

Divalent brines contain salts that have divalent cations; these salts include calcium chloride, calcium bromide, and zinc bromide. A divalent brine might consist of a single salt or a blend of salts, depending on the required brine density and crystallization point.

The corrosivity of these brines depends on their density and chemical composition. Laboratory data show that the addition of calcium chloride lowers the rate of corrosion, while the addition of zinc bromide rapidly increases the rate of corrosion.

Corrosive agents

When working with completion or workover fluids, the two corrosive agents to monitor are oxygen and hydrogen sulfide.

Oxygen. The oxygen content of fluids is difficult to determine, and most engineers in the field do not have access to the proper equipment. Because the dissolved oxygen content varies as conditions change during the day, it is difficult to select a set feed rate of oxygen scavenger to remove a known concentration of oxygen.

Laboratory tests show that the oxygen content of calcium chloride, calcium bromide, and zinc bromide brines is very low. The solubility of gases in a liquid is

directly related to the total dissolved-solids concentration of that liquid. The higher the dissolved-solids content, the lower the solubility of gases in the liquid. Table 2-4 lists oxygen concentrations measured in stock brine at room temperature.

Brine density, lb/gal (sg)	Oxygen concentration, ppm
11.6 (1.39) $CaCl_2$	0.1-0.2
14.2 (1.70) $CaBr_2$	0.05-0.1
19.2 (2.30) $CaBr_2$/ $ZnBr_2$	0.4-0.6

Table 2-4: Stock brines and oxygen concentrations. The oxygen content of calcium chloride, calcium bromide, and zinc bromide brines is very low.

Note: In a well at elevated temperatures, the oxygen content should be much lower.

Some products used as oxygen scavengers contain sulfites that react with the dissolved oxygen in fluids to form sulfates, eliminating the corrosive effects of the dissolved oxygen. Calcium brines should not be treated with oxygen scavengers containing sulfides because chemicals could precipitate calcium scale and cause problems. In a packer-fluid application where there is a static system with no aeration of the fluid, the dissolved oxygen content is so low that an oxygen scavenger usually is not required.

Hydrogen sulfide. In solids-enhanced systems, the most often used hydrogen-sulfide scavenger is zinc carbonate. The zinc reacts with the soluble sulfide ions to form zinc sulfide, which is insoluble and precipitates as an unreactive compound. In solids-free systems, soluble zinc bromide salt serves the same function and absorbs the hydrogen sulfide.

In operations where hydrogen-sulfide contamination is expected, offset the hydrogen sulfide's acidic nature by maintaining a proper pH in the brine, as outlined in Table 2-5.

Brine	Recommended pH	Treatment
Non-zinc	7.0	Caustic soda or lime
Calcium	7.0-10.5	Caustic soda or lime
Zinc	3.0-5.0	Lime

Table 2-5: Proper brine pH. Maintain the recommended pH by adding caustic soda or lime.

Corrosion inhibitors

A corrosion inhibitor is a chemical product that substantially reduces metallic loss when it is added in small concentrations to a corrosive environment. Chemicals used as corrosion inhibitors include both inorganic and organic compounds. The products recommended for treating corrosive agents in completion and workover fluids are:

- BARACOR 100
- BARACOR 450

Corrosion test

The best and most direct method for testing for the presence of corrosion is the use of a drillstring coupon. A drillstring coupon is a ring made from a section of tubing. The coupon, which has a smooth surface, is placed at a predetermined depth during a round trip. Later, it is removed and inspected. The coupon is weighed both before and after downhole exposure. A high metal loss after exposure indicates corrosion is taking place. The coupon surface is another indicator of

corrosion. When there is evidence of pitting on the coupon, pitting is also most likely occurring on the drillpipe.

Ordering coupons

Coupons can be ordered from the FANN Instrument Company. Table 2-6 lists the products available.

Drillpipe size and type	Recommended coupon
2 7/8-in internal flush and 3 ½-in slim hole	No. 636-18 2 ½-in OD x 0.250-in wall
3 ½-in extra hole and 3 ½-in full hole	No. 636-19 2 3/4-in OD x 0.188-in wall
3 ½-in internal flush and 3 ½-in extra hole	No. 636-20 3-in OD x 0.313-in wall
4-in full hole	No. 636-21 3 1/4-in OD x 0.250-in wall
4-in internal flush and 4 ½-in extra hole	No. 636-23 3 1/4-in OD x 0.3125-in wall
4 ½-in full hole and 4 ½-in extra hole and 4-in internal flush	No. 636-24 3 5/8-in OD x 0.375-in wall
4 ½-in internal flush and 5-in extra hole	No. 636-25 4 ½-in OD x 0.1325-in wall
5 9/16-in or 5 ½-in API regular or full hole and 6 5/8-in API regular	No. 636-26 4 5/8-in OD x 0.500-in wall
4 ½-in extra hole	No. 636-29 3 13/16-in OD x 0.200-in wall
5-in x H tool joint	No. 636-31 4 3/16-in OD x 0.2185-in wall
Note: Plastic coated corrosion coupons are available on request.	

Table 2-6: Coupons. Coupons are available for a variety of drillpipe sizes.

Coupons are weighed to 0.1 milligram and the weight and ring number are permanently recorded at the FANN Instrument Company. For shipment, the rings are placed in a plastic bag containing an inert desiccant, such as

silica gel, and are sealed in a sturdy envelope. The coupon's size, number, and weight are recorded on the envelope.

Handling coupons

Follow these steps when handling coupons in the field:

1. Remove the coupon from its package and place the coupon in the tool joint box.

   Caution: Handle the coupon carefully to prevent damage to the coupon.

2. Save the envelope and plastic bag for shipping the coupon to the laboratory.
3. Make up the joint.
4. Leave the coupon in the pipe string for the desired number of bit runs (usually 50 hours).

   Note: A visual inspection of the coupon, or previously determined corrosion rates, determine the actual length of exposure.

5. Remove the coupon, wipe it dry, and smear it with grease or heavy oil.
6. Pack the coupon in the plastic bag and envelope along with a copy of the mud report.
7. Ensure the following information appears on the envelope:
   - Mud properties, such as salt content
   - pH value
   - Inhibitor treatments in effect
8. Ship the coupon to the laboratory by the fastest means possible.

Test results

At the laboratory, the coupon is cleaned and weighed, and the corrosion rate is determined.

Corrosion rates are reported as weight loss in pounds per square foot per year according to the following formula:

$$\text{Weight loss, lb/sqft/yr} = \frac{\text{Weight loss grams} \times \text{ring factor}}{\text{Exposure time, hours}}$$

Uniform corrosion rates below 2.0 lb/sq ft/yr are considered acceptable.

Corrosion troubleshooting chart

Oxygen from water additions	
Source: Water additions	**By-product:** Oxides of iron
Indication: Concentration cell pitting under barrier or deposits and pits filled with black magnetic corrosion by-products	**Tests:** Black to red dust Some by-product insoluble in 15% HCl Some by-product attracted to magnet
Treatment: • Treat with an oxygen scavenger having a range equivalent of 2.5 to 10 lb/hr of sodium sulfite. • Maintain 20 to 300 mg/L sulfite residual.	
Oxygen from mixing and solids-control equipment	
Source: Mixing and solids-control equipment	**By-product:** Oxides of iron
Indication: Concentration cell pitting under barrier or deposits and pits filled with black magnetic corrosion by-products	**Tests:** Black to red dust Some by-product insoluble in 15% HCl Some by-product attracted to magnet
Treatment: • Coat pipe with film-forming inhibitors to reduce atmospheric attack and cover concentration cell deposits. • Reduce air entrapment in pits. • Defoam drilling fluid.	

(continued on next page)

Oxygen from aerated drilling fluids	
Source: Aerated drilling fluids	**By-product:** Oxides of iron
Indication: Severe pitting	**Tests:** Black to red dust Some by-product insoluble in 15% HCl Some by-product attracted to magnet
Treatment: • Maintain a high pH and keep drillpipe free of mineral scale deposits with scale inhibitor. • Coat pipe with filming inhibitors.	
Oxygen from the atmosphere	
Source: Atmosphere	**By-product:** Oxides of iron
Indication: Generalized to localized corrosion	**Tests:** Black to red dust Some by-product insoluble in 15% HCl Some by-product attracted to magnet
Treatment: • Wash equipment free of salts and mud products. • Spray equipment with atmospheric filming inhibitors.	
Hydrogen sulfide	
Source: • Formation • Thermally degraded mud products	**By-product:** Iron sulfide
Indications: • Localized to sharp pitting • Dark blue-to-black film on equipment • Sulfide stress corrosion cracking (SSCC) failures • Rotten egg odor	**Tests:** • Acid arsenic solution produces a bright yellow precipitate, soluble in 15% HCl • Lead acetate test
Treatment: • Maintain high pH with caustic soda. • For 0-100 ppm sulfide, add 3-5 lb/bbl (9-14 kg/m^3) iron oxide and/or 0.1-0.5 lb/bbl (0.3-1.4 kg/m^3) zinc carbonate/zinc oxide to remove sulfide ions. *Note: The combined treatments of iron oxide and zinc compounds should provide lower sulfide ion contamination in most drilling fluids.*	

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Carbon dioxide	
Source: • Formation • Thermally degraded mud products	**By-product:** Iron carbonate
Indications: • Localized corrosion to pitting • Dark brown-to-black film	**Test:** Slow effervescence in 15% HCl
Treatment: Maintain basic pH with caustic soda, lime, or BARACOR 95 to neutralize the acid-forming gas.	
Bacteria	
Source: Bacteria	**By-product:** Carbon dioxide; hydrogen sulfide
Indications: • Fermentation of organic mud additives • Change in viscosity • Lower pH • Sour odor • Gas formation	**Tests:** Phenol-red serum test (aerobic bacteria) Marine anaerobic serum test (anaerobic bacteria)
Treatment: Add biocides.	
Dissolved salts	
Source: Dissolved salts	**By-product:** Oxides of iron
Indications: • Localized corrosion • Pitting	**Test:** Black to red rust
Treatment: Add film-forming inhibitors.	

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Mineral scale deposits	
Source: Formation and mud materials	**By-product:** Iron products beneath mineral deposit
Indication: Corrosion cell pits beneath deposit	**Test:** White mineral scale: calcium, barium and/or magnesium compounds

Treatment:

- Slowly and continuously add scale inhibitor at 5-15 mg/L.
- Reduce treatments of scale inhibitor when phosphate residual exceeds 15 mg/L.
- Use 1 gal/1,000 bbl (0.25 L/m^3) mud/day for maintenance treatment under normal drilling conditions.

Product information

Product	Function	Description	Treatment
ALDACIDE G	Microbiocide	Glutaraldehyde solution	0.2-0.5 lb/bbl (0.6-1.4 kg/m^3)
BARACOR 44	Hydrogen sulfide scavenger	Powdered zinc compound	Pretreat with 2-5 lb/bbl; additional treatments as required (6-14 kg/m^3)
BARACOR 95	Alkalinity control agent	Liquid amine compound	0.25-1.4 lb/bbl (0.7-4 kg/m^3)
BARACOR 100	Corrosion inhibitor	Film-forming amine	Clear fresh water or salt water: 21-42 gal/100 bbl fluid. Heavy brine: 0.5-2.0% by volume (5-10 L/m^3).
BARACOR 450	Corrosion inhibitor	Cyanogen-based inorganic compound	0.2-0.4% by weight
BARACOR 700	Corrosion inhibitor	Blend of phosphonates and alkyl phosphates	0.5-1.5 lb/bbl (1.4-4 kg/m^3)
BARAFILM	Corrosion inhibitor	Film-forming amine	1.5-2 gal/1,000 ft of pipe every 1-4 hours (1.9-2.5 L/100 m)
BARASCAV D	Oxygen scavenger Thermal extender for polymers	Powdered sodium sulfite	0.5-1 lb/gal of fresh water (1.4-2.9 kg/m^3)
BARASCAV L	Oxygen scavenger Thermal extender for polymers	Liquid ammonium bisulfite	Initially 0.1-0.5 lb/bbl (0.3-1.4 kg/m^3)
NO-SULF	Hydrogen sulfide scavenger	Blend of zinc compounds	Pretreat with 0.1-5 lb/bbl (0.3-14 kg/m^3)
STABILITE	Thinner/scale inhibitor	Organophosphonate	0.1-1 lb/bbl (0.3-3 kg/m^3)

CHAPTER 3

Displacement

The Complete Fluids Company

Contents

Overview

Displacement is the process of changing fluids in a well by substituting the fluid in place with a different fluid. Specially designed spacers are formulated to provide separation of the two fluids whether the displacement is mud to mud, brine to mud, or mud to brine.

Displacement methods include direct and indirect. Direct displacement is used when the fluid is displaced directly with a displacement fluid. Indirect displacement uses large amounts of water to flush out the wellbore before circulating the displacement fluid.

Displacement procedure

To ensure a displacement with minimal contamination, follow these steps:

1. Condition the fluid to be displaced by adjusting the rheological properties of the fluid to achieve the lowest practical yield point.
2. Prepare spacers.

   Note: In a nondeviated hole, a spacer should cover 500 feet (153 m) in the largest annular section. In a deviated hole, a spacer should cover a minimum of 1,000 feet (305 m) in the largest annular section. See Table 3-1 for recommended spacers.

3. Prepare the equipment and the well.

   a. Flush and clean all lines, tanks, and manifolds that will contact the displacement fluid.
   b. Secure water outlets to prevent dilution and/or contamination of the displacement fluid.

Note: If displacing a drilling fluid with a brine, a scraper trip is recommended to ensure there are no solids adhering to the walls of the casing or the borehole.

4. Run pipe (i.e., drillpipe, tubing) to displacement depth.
5. Pump spacers.
6. Pump displacement fluid.

   Notes:

   - *Once displacement begins, do not stop the pumping operation. Maintain a constant circulation rate.*
   - *Reciprocate and rotate the drillpipe at least 1 joint every 15 minutes to prevent channeling in the annulus.*

Spacer displacement recommendations and formulation guidelines

Recommended spacers

Table 3-1 lists the recommended spacers to use for various displacements.

Fluid to be displaced	Displacement fluid			
	OBM	WBM	Synthetic	Brine
OBM	High viscosity oil-based mud	Base oil High viscosity water-based mud	High viscosity PETROFREE/ PETROFREE LE/ XP-07 muds	ENVIRO-SPOT BARAKLEAN LIQUI-VIS NP/EP* or BROMI-VIS**

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Fluid to be displaced	Displacement fluid			
	OBM	**WBM**	**Synthetic**	**Brine**
WBM	Water High viscosity oil-based mud	Water	Water High viscosity PETROFREE/ PETROFREE LE/ XP-07 muds	Water High pH BARAKLEAN FL LIQUI-VIS NT*, LIQUI-VIS EP, or BROMI-VIS** VERSAFLOC M341 VERSAFLOC M441 LIQUI-VIS NT or LIQUI-VIS EP
PETROFREE PETROFREE LE XP-07	High viscosity oil-based mud	BARAZAN PLUS or BARAZAN D PLUS	High viscosity PETROFREE/ PETROFREE LE/ XP-07 muds	BARAZAN PLUS or BARAZAN D PLUS BARAKLEAN NS BARAKLEAN FL Water BARAKLEAN NS
Brine	High viscosity oil-based mud	LIQUI-VIS NT*, LIQUI-VIS EP, or BROMI-VIS*** Water	High viscosity PETROFREE/ PETROFREE LE/ XP-07 muds	LIQUI-VIS NT*, LIQUI-VIS EP, or BROMI-VIS**

* Use LIQUI-VIS for nonbromine brines.
** Use BROMI-VIS for bromine brines.

Table 3-1: Recommended spacers. The type(s) of spacer(s) to use depends on both the fluid being displaced and the displacement fluid.

Spacer formulation guidelines

Table 3-2 provides recommended formulation guidelines for various spacers.

Spacer	Recommended formulation
BARAKLEAN	1 drum/32 bbl (5.09 m^3) of water
BARAKLEAN FL	4-6 percent concentration in water
BARAKLEAN NS	4-6 percent concentration in water
BARAZAN PLUS or BARAZAN D PLUS	1.0-1.5 lb/bbl (3-4 kg/m^3) (weighted to desired density)
BROMI-VIS	Minimum of 150 sec/qt (150 sec/L)
ENVIRO-SPOT	6-12 lb/bbl (17-34 kg/m^3) in the base mud (weighted to desired density)
High viscosity: OBM/Synthetic	Displacement fluid viscosified with conventional gellants
LIQUI-VIS NT/LIQUI-VIS EP	Minimum of 150 sec/qt (150 sec/L)
VERSAFLOC M341	1 drum/100 bbl of water or brine (requires a minimum Cl^- content of ± 5000 mg/L) (not to be used with zinc bromide brines)
VERSAFLOC M441	1 drum/100 bbl of zinc bromide brine

Table 3-2: Spacer formulation guidelines. Use these guidelines when formulating spacers.

Note: If offshore, use sea water.

CHAPTER 4

DRIL-N Fluid Systems

The Complete Fluids Company

Contents

Overview

DRIL-N Fluids are designed to be essentially non-damaging to the producing formation, provide superior hole cleaning, allow easy clean-up and be cost effective.

These fluids address the wide range of problems encountered in horizontal drilling, completion, and workover operations. These systems are designed to provide the lowest filtration rate possible in order to minimize or prevent formation damage.

Bridging off the production zone is a key to preventing formation damage. Bridging materials that are utilized in DRIL-N fluids include sized calcium carbonate an sized salt

When bridging production zones, the correct sizing of particles becomes important. The pore diameter of the formation must be known to effectively bridge. An industry rule of thumb for estimating an unknown pore diameter (microns) is to take the square root of the permeability in millidarcies. To effectively bridge off the production zone, 20-30% by weight of the bridging material should be one-third of the pore size in microns.

Filtration tests on DRIL-N fluids are conducted using a ceramic disc which simulates as close as possible the pore size of the formation. These tests can be utilized in the field to determine proper application of the DRIL-N fluids system.

Baroid has six unique systems, each designed to do a specific job of addressing a specific set of conditions and objectives. The following table gives a brief description of each system. A more detailed description is found in each system section.

DRIL-N Fluid systems	
System	**Description**
BARADRIL-N	Sized calcium carbonate system
COREDRIL-N	All oil drilling and coring system
MAXDRIL-N	Mixed metal silicate system
QUIKDRIL-N	Clay and solids free, polymer system
SHEARDRIL-N	Clay and solids free, modified polymer system
SOLUDRIL-N	Sized salt system

Table 4-1: DRIL-N Fluid systems. This table describes DRIL-N fluid systems.

The following table lists the DRIL-N systems in this chapter, providing a matrix that rates each system according to its applicability for various drilling situations. Systems are identified as:

❍ Good
◗ Better
● Best

Systems	DRIL-N Fluid situations				
	Reactive shales	**Depleted zones**	**Horizontal/High angle drilling**	**Minimize formation damage**	**Clean -up**
BARADRIL-N	◗	●	◗	●	◗
COREDRIL-N	●	●	◗	●	◗
MAXDRIL-N		●	●	❍	❍
QUIKDRIL-N	◗		❍	●	●
SHEARDRIL-N	◗		❍	●	●
SOLUDRIL-N	●	●	◗	●	●

Table 4-2: DRIL-N fluids versus drilling situations. This table rates DRIL-N fluids as good, better or best under various drilling situations.

BARADRIL-N

Overview

The BARADRIL-N system provides acid soluble drilling, completion, and workover fluid compositions. The BARADRIL-N system is designed for non-damaging drilling when fluid loss and formation stability are of primary concern. Return permeabilities are excellent with the BARADRIL-N system and the filtercake is easily removed by treating with hydrochloric acid.

Formulation

- Products are listed in order of addition.
- Density range 8.5 - 14.5 lb/gal (1.02-1.74 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
N-VIS	Viscosifier	0.25-1 (0.7-3)
N-VIS P PLUS	Viscosifier/Filtration control	1-5 (3-14)
N-DRIL HT PLUS	Filtration control	2-10 (6-29)
BARACARB 5/25/50/150	Weighting/ Bridging agent	As needed
BARABUF	Alkalinity	0.1-3.0 (0.3-9)

Table 4-3: BARADRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating BARADRIL-N fluids.

Formulation guidelines

- BARADRIL-N fluids may be formulated in freshwater ,seawater , potassium chloride, sodium chloride, calcium chloride, sodium bromide, or calcium bromide brines.

- Add all polymers slowly to prevent the formation of “fish eyes”.
- Add BARACARB as needed for density and bridging requirements.
- Add BARABUF for pH control

Base fluid	BARADRIL-N fluid density, lb/gal (sg)
Freshwater	8.8-10.0 (1.05-1.20)
Seawater	9.0-10.0 (1.08-1.20)
Potassium chloride	9.0-12.0 (1.08-1.50)
Sodium chloride	9.0-12.5 (1.08-1.50)
Sodium bromide	12.0-14.5 (1.44-1.74)
Calcium bromide	12.0-16.0 (1.44-1.92)

Table 4-4: BARADRIL-N base fluid guidelines. This table lists base fluids and their recommended corresponding density ranges for formulating BARADRIL-N fluids.

Caution: When selecting a saturated salt fluid be aware of it’s crystallization point.

Maintenance guidelines

- Add BARABUF to maintain alkalinity in the 8 - 10 pH range.
- BARACARB addition should be sized according to the mean pore diameter size of the formation.

Note: "Rule of thumb" To effectively bridge off the production zone, 20-30% by weight of the bridging material (BARACARB) should be one-third of the pore size in microns.

COREDRIL-N

Overview

COREDRIL- N fluids are 100% oil/synthetic drilling fluids (diesel, mineral, ester or crude) that have been developed to control the formation damage that could be caused by conventional drilling operations. The COREDRIL-N system contains an optimum concentration of BARACARB designed to bridge rock pores, thus providing low filtration rates - minimizing fluid invasion into potential pay zones. COREDRIL-N fluids use passive emulsifiers which reduce the risk of creating emulsion blockage and preserve the wettability characteristics of the reservoir rocks.

Formulation

- Products are listed in order of addition.
- Density range 7.5 - 12.0 lb/gal (0.90-1.44 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Oil/Synthetic	Base fluid	As needed
EZ-CORE	Passive emulsifier	1-5 (3-14)
Lime	Alkalinity/Emulsification aid	1-3 (3-9)
BARABLOK or BARABLOK 400 or DURATONE HT	High temp filtration control	5-25 (14-71)
N-VIS O	Viscosifier/Suspension	6-15 (17-43)
BARACTIVE	Polar additive	2-3% (2-3%)
BARACARB 5/25/50/150	Weighting/ Bridging agent	As needed
BARAPLUG 20/50/6-300	Weighting/ Bridging agent	As needed

Table 4-5: COREDRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating COREDRIL-N fluids.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

Formulation guidelines

- COREDRIL-N fluids may be formulated with diesel, mineral oils, esters, and synthetics.
- Provide sufficient mixing time and high shearing action for proper yield
- Lime addition provides alkalinity to aid in emulsification

Maintenance guidelines

- Minimize invasion of water from formation through proper control of hydrostatic pressure.
- Do not contaminate fluid with water from surface equipment.

Note: "Rule of thumb" To effectively bridge off the production zone, 20-30% by weight of the bridging material (BARACARB or BARAPLUG) should be one-third of the pore size in microns.

MAXDRIL-N

Overview

The MAXDRIL-N system is a mixed-metal silicate system (MMS) designed for drilling, milling, and completion operations. MAXDRIL-N fluids provide borehole stability and superior hole cleaning for milling casing and drilling highly deviated/horizontal sections. This fluid is especially effective when drilling in unconsolidated, unstable, stressed or faulted formations.

MAXDRIL-N fluids form a low permeability filtercake that restricts solids and fluid invasions into the formation, thus reducing damage to the formation.

Formulation

- Products are listed in order of addition.
- Density range 8.8 - 13.0 lb/gal (1.06-1.56 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Soda ash	Hardness reducer	0.05-0.25 (0.15-0.7)
AQUAGEL GOLD SEAL	Viscosifier	8-15 (23-43)
Caustic soda	Alkalinity	As needed for pH 9.5-11.5
N-DRIL	Fluid Control	2-6 (6-17)
N-VIS HI	Viscosifier	0.075 lb per lb AQUAGEL (0.075 kg per kg AQUAGEL)
BARACARB 5/25/50/150	Weighting/Bridging agent	As needed

Table 4-6: MAXDRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating MAXDRIL-N fluids.

Formulation guidelines

- Treat fresh water with soda ash to reduce hardness below 60 mg/L to improve the yield of AQUAGEL GOLD SEAL.
- Prehydrate AQUAGEL GOLD SEAL for at least one hour before adding caustic soda.

Caution: Do not add any chemicals (i.e., fluid loss control additives or thinners) that are not on the formulation list.

Note: For a seawater system, premix chemicals in freshwater and add the premix to salt water in the pits.

Maintenance guidelines

- Add prehydrated AQUAGEL GOLD SEAL and/or N-VIS HI, when necessary, to increase viscosity.
- Dilute with water when necessary to decrease viscosity.
- Avoid using more than 0.1 lb of N-VIS HI per lb (.1 kg/kg) of AQUAGEL GOLD SEAL.
- Maintain pH between 9.5 and 11.5 with caustic soda.

Caution: Any anionic product may cause adverse deflocculation or dispersion.

Note: "Rule of thumb" To effectively bridge off the production zone, 20-30% by weight of the bridging material (BARACARB) should be one-third of the pore size in microns.

Contamination

Clean tanks prior to addition of fluid or products. When milling casing the old drilling fluid left

behind casing may cause deflocculation or thinning.

Keep calcium levels below 60 mg/L with soda ash.

QUIKDRIL-N

Overview

QUIKDRIL-N fluids are designed as water-based, solids-free polymer drilling fluids QUIKDRIL-N fluids are especially beneficial in slimhole drilling or coiled tubing operations when minimizing circulation pressure is critical.

Formulation

- Products are listed in order of addition.
- Density range 8.4 - 12.7 lb/gal (1.01-1.52 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
N-VIS	Viscosifier	1-2 (3-6)
N-DRIL HT PLUS	Viscosifier/ Filtration control	3-5 (9-14)
BARABUF	Alkalinity	2-3 (6-9)

Table 4-7: QUIKDRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating QUIKDRIL-N fluids.

Formulation guidelines

- When mixing N-VIS and N-DRIL HT PLUS, add slowly and agitate to insure proper hydration of polymers.
- Use brines to obtain the required density. Refer to the brine density tables in the chapter titled Completion fluids for density guidelines.

Caution: Do not use in calcium chloride brines heavier than 11.0 lb/gal. Do not use in calcium bromide or zinc bromide brines.

Maintenance guidelines

- Maintain the Brookfield viscometer between 45,000 and 60,000 cP using the 0.5 spindle.
- N-VIS L may be substituted for N-VI .S
- BARALUBE GOLD SEAL will aid in reducing torque and circulating pressures.

SHEARDRIL-N

Overview

SHEARDRIL-N fluids are designed as a solids-free modified polymer drilling fluid. SHEARDRIL-N fluids provide maximum penetration rates while minimizing formation damage.

Formulation

- Products are listed in order of addition.
- Density range 8.4 - 15.0 lb/gal (1.01-1.80 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
N-VIS	Viscosifier	0.25-1 (0.7-3)
N-DRIL HI	Viscosifier/ Filtration control	1-3 (3-9)
N-DRIL LO	Viscosifier/Filtration control	1-3 (3-9)
Caustic soda	Alkalinity	0.05-1 (0.15-3)
BARABUF	Alkalinity	1-3 (3-9)

Table 4-8: SHEARDRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating SHEARDRIL-N fluids.

Formulation guidelines

- When mixing N-DRIL HI and N-DRIL LO, add slowly and agitate to insure proper hydration of polymers.
- Use brines to obtain the required density. Refer to the brine density tables in the chapter titled Completion fluids for density guidelines.

Caution: Do not use brines containing zinc.

Maintenance guidelines

- In saltwater fluids use BARABUF to maintain alkalinity.
- In other systems maintain alkalinity with caustic soda.

SOLUDRIL-N

Overview

SOLUDRIL- Nfluids are designed for drilling, completion or workover operations in horizontal and vertical wells. SOLUDRIL-N fluids utilize BARAPLUG (sized salt) and a cross-linked polymer to provide superior rheological and filtration control.

Formulation

- Products are listed in order of addition.
- Density range 10.4 - 14.5 lb/gal (1.25-1.74 sg)

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Brine (saturated)	Base fluid	Saturate based on the brine used
N-VIS	Viscosifier	0.25-1 (0.7-3)
N-VIS P PLUS	Viscosifier/Filtration control	3-5 (9-14)
N-DRIL HT PLUS	Filtration control	5-10 (14-29)
BARAPLUG 6-300/20/40/50	Weighting/Bridging agent	As needed
BARABUF	Alkalinity	1-3 (3-9)

Table 4-9: SOLUDRIL-N product guidelines. This table lists products and provides typical product concentrations for formulating SOLUDRIL-N fluids.

Formulation guidelines

- SOLUDRIL-N fluids may be formulated in saturated potassium chloride, sodium chloride, calcium chloride, or sodium bromide brines.
- Add all polymers slowly to prevent the formation of “fish eyes”.
- Add BARAPLUG as needed for density and bridging requirements.

- Add BARABUF to maintain alkalinity in the 8-10 pH range.

Base fluid	SOLUDRIL-N fluid density, lb/gal (sg)
Potassium chloride	10.0-12.0 (1.20-1.44)
Sodium chloride	10.4-12.5 (1.25-1.50)
Calcium chloride	12.0-13.5 (1.44-1.62)
Sodium bromide	13.0-14.5 (1.56-1.74)

Table 4-10: SOLUDRIL-N base fluid guidelines. This table lists base fluids and their corresponding density ranges for formulating SOLUDRIL-N fluids.

Caution: When selecting a saturated salt fluid be aware of it's crystallization point.

Maintenance guidelines

- Any fluid dilution should be made with the saturated brine used for the base fluid.
- BARAPLUG additions should be sized according to the mean pore diameter of the formation.

Note: "Rule of thumb" To effectively bridge off the production zone, 20-30% by weight of the bridging material (BARAPLUG) should be one-third of the pore size in microns.

CHAPTER 5

Field tests

Contents

Overview

This chapter contains procedures for field testing water-based muds (WBM), oil-based muds (OBM), synthetics, and completion/workover fluids (CWO). The following table lists the field tests in this chapter and the systems to which they apply.

Test	WBM	OBM	Synthetics	CWO
Alkalinity	✓	✓	✓	
Alkalinity: Filtrate (P_f/M_f)	✓			
Alkalinity: Alternate filtrate (P_1/P_2)	✓			
Brine clarity				✓
Brine specific gravity (density)				✓
Carbonate concentration	✓			✓
Chloride content	✓	✓	✓	✓
Crystallization point				✓
Density: Baroid mud balance	✓	✓	✓	✓
Density: Pressurized mud balance	✓	✓	✓	✓
Electrical stability		✓	✓	
Filtrate: LTLP	✓	✓	✓	
Filtrate: HTHP	✓	✓	✓	
Hardness: Calcium	✓			✓
Hardness: Total	✓			✓
Iron content				✓

(continued on next page)

Test	WBM	OBM	Synthetics	CWO
Methylene blue test (MBT)	✓			
pH: Paper method	✓			✓
pH: Strip method	✓			✓
pH: Meter method	✓			✓
Polymer concentration	✓			
Potassium: Strip method	✓			✓
Potassium: Centrifuge method	✓			✓
Retort analysis	✓	✓	✓	✓
Rheological properties	✓	✓	✓	✓
Sand content	✓	✓	✓	✓
Sulfide concentration (GGT)	✓	✓	✓	✓
Water-phase salinity		✓	✓	

Table 5-1: Field tests. The field tests in this chapter include tests for water-based muds (WBM), oil-based muds (OBM), synthetics, and completion/workover fluids (CWO).

Testing procedures

Alkalinity: WBM

Objective

Determine the alkalinity (P_m) of a water-based mud (WBM).

Unit

mL

Example

P_m = 1.2 mL of 0.02N (N/50) sulfuric acid solution

Equipment

- Titration dish
- 3-mL syringe (without needle)
- 5-mL pipette
- Stirring rod
- 50-mL graduated cylinder (250-mL for lime muds)
- 0.02N (N/50) sulfuric acid solution
- Phenolphthalein indicator solution
- Distilled water

Procedure

1. Collect a fluid sample.
2. Transfer 1 mL of the sample to the titration dish using the syringe.
3. Add 50 mL of distilled water to the titration dish and stir. Note the color of the mixture for Step 5.

   Note: For lime muds, use 200 mL of distilled water.

4. Add 10 to 15 drops of phenolphthalein indicator solution to the titration dish and stir.

If...	Then...
A pink or red color develops,	Go to Step 5.
There is no color change,	P_m equals zero. Go to Step 6.

5. Add the sulfuric acid solution one drop at a time to the titration dish until the color changes from pink or red to the original color.
6. Record the amount of sulfuric acid solution used (in mL) as P_m.

Alkalinity: OBM/ Synthetics

Objective

Determine the whole-mud alkalinity and lime content of an oil-based mud (OBM) or synthetics.

Unit

mL

Example

Alkalinity = 1.8 mL of 0.1N (N/10) sulfuric acid solution

Equipment

- 500-mL Erlenmeyer flask with a rubber stopper or a pint jar with a lid
- 3-mL disposable syringe
- 50-mL graduated cylinder
- 250-mL graduated cylinder
- Two 1-mL pipettes
- Two 5-mL pipettes
- Arcosol PNP® solvent

  Note: If the solvent is not available, the base fluid can be used.

- Distilled water

  Note: If distilled water is not available, nondistilled water can be used. The pH of the water must be approximately 7.

- Phenolphthalein indicator solution
- 0.1N (N/10) sulfuric acid solution
- 0.1N (N/10) sodium hydroxide

Procedure

1. Collect a drilling fluid sample.
2. Measure 100 mL of Arcosol PNP solvent into the Erlenmeyer flask.

3. Add 1.0 mL of the fluid sample to the Erlenmeyer flask using the syringe.
4. Stopper the flask and shake vigorously.
5. Add 200 mL of distilled water and 10 to 15 drops of phenolphthalein indicator solution to the flask.
6. Stopper the flask and shake vigorously for a minimum of two minutes.
7. Allow the phases to separate.

If...	Then...
A pink color develops and remains,	Go to Step 8.
A pink color does not develop,	Alkalinity is zero. Go to Step 16.

8. Add 3 mL of sulfuric acid solution to the flask using the 5-mL pipette.
9. Stopper the flask and shake vigorously.
10. Allow the phases to separate.

If...	Then...
The solution remains pink,	Go to Step 11.
The solution turns colorless,	Go to Step 12.

11. Continue to add sulfuric acid solution in 3-mL increments until the pink color disappears.

    Note: Shake the solution after each addition of sulfuric acid.

12. Record the volume of sulfuric acid used in mL.
13. Back titrate with sodium hydroxide using the 1-mL pipette until the pink color first reappears and remains.

Note: Shake the solution after each addition of sodium hydroxide. Add sodium hydroxide only until the pink color reappears.

14. Record the volume of sodium hydroxide used in mL.
15. Calculate alkalinity.

    Alkalinity = mL N/10 sulfuric acid - mL N/10 sodium hydroxide

16. Calculate excess lime pounds per barrel of mud.

    Excess lime, lb/bbl = 1.3 × alkalinity

Alkalinity: Filtrate (P_f/M_f)

Objective

Determine the amounts of soluble ions that contribute to alkalinity in a water-based drilling fluid.

Note: If the mud contains high concentrations of organic thinners (i.e., CARBONOX), use the alternate filtrate alkalinity (P_1/P_2) method.

Unit

mL

Example

P_f = 0.3 mL of 0.02N (N/50) sulfuric acid solution

M_f = 1.3 mL of 0.02N (N/50) sulfuric acid solution

Equipment

- Titration dish
- 1-mL pipette
- 2-mL pipette
- 5-mL pipette
- Stirring rod
- Distilled water
- 0.02N (N/50) sulfuric acid solution
- Phenolphthalein indicator solution

- Methyl orange indicator solution

  Note: As an option, use methyl purple indicator solution or bromocresol green.

Procedure

1. Collect a filtrate sample using the API filtrate (LPLT) method.
2. Transfer 1 mL of the filtrate to the titration dish using the 1-mL pipette.
3. Add 10 to 15 drops of phenolphthalein indicator solution to the titration dish.

If...	Then...
There is a color change,	Go to Step 4.
There is no color change,	P_f is zero. Go to Step 6.

4. Add the sulfuric acid solution slowly to the titration dish (using the 2- or 5-mL pipette) until the color changes from pink or red to the original filtrate color.
5. Record the amount of sulfuric acid solution used in mL as P_f .
6. Add 10 to 15 drops of methyl orange indicator solution to the filtrate mixture.
7. Continue titrating with the sulfuric acid solution until the color changes from orange to salmon pink.
8. Record the total amount of sulfuric acid solution used, including the amount from the P_f test, as the M_f value.
9. Calculate the concentration of hydroxyl (OH^-), carbonate (CO_3^{-2}), and bicarbonate (HCO_3^-) ions using the following table.

Concentration, mg/L			
Criteria	**OH^-**	**CO_3^{-2}**	**HCO_3^-**
$P_f = 0$	0	0	1,220 M_f
$2P_f < M_f$	0	1,200 P_f	1,220 $(M_f - 2P_f)$
$2P_f = M_f$	0	1,200 P_f	0
$2P_f > M_f$	340 $(2P_f - M_f)$	1,200 $(M_f - P_f)$	0
$P_f = M_f$	340 M_f	0	0

Table 5-2: Concentration calculations. Use these calculations for hydroxide (OH^-), carbonate (CO_3^{-2}), and bicarbonate (HCO_3^-) ions in water-based drilling fluids.

$$\text{Excess lime, lb/bbl} = 0.26 \text{ x } [P_m - (P_f \text{ x } F_w)]$$

$$\text{Excess lime, kg/m}^3 = 0.74 \text{ x } [P_m - (P_f \text{ x } F_w)]$$

An approximation of excess lime can be obtained by:

$$\text{Excess lime, lb/bbl} = (P_m - P_f)/4$$

$$\text{Excess lime, kg/m}^3 = (P_m - P_f) \text{ x } 0.7$$

Where

P_f is the phenolphthalein endpoint of the filtrate
P_m is the phenolphthalein endpoint of the mud
F_w is the water fraction

Alkalinity: Alternate (P_1/P_2)

Objective

Determine the amounts of soluble ions that contribute to alkalinity in a water-based drilling fluid.

Unit

mL

Example

P_1 = 11.5 mL of 0.02N (N/50) hydrochloric acid solution

P_2 = 9.8 mL of 0.02N (N/50) hydrochloric acid solution

Equipment

- 1-mL volumetric pipette
- 2-mL volumetric pipette
- Titration dish
- 25-mL graduated cylinder
- 5-mL or 10-mL graduated cylinder
- Stirring rod
- 3-mL syringe
- Distilled water
- Barium chloride solution (10 percent, neutralized to pH 7 with NaOH)
- Phenolphthalein indicator solution
- 0.02N (N/50) hydrochloric acid solution
- 0.1N (N/10) sodium hydroxide solution

Procedure

1. Collect a filtrate sample using the API filtrate (LPLT) method.
2. Determine the P_f alkalinity of the sample using Steps 2 through 5 of the P_f/M_f procedure.

   Note: Substitute hydrochloric acid for sulfuric acid solution.

3. Determine the P_1 alkalinity.
   a. Transfer 1.0 mL of filtrate to the titration dish.
   b. Add 24 mL of distilled water to the titration dish.
   c. Add exactly 2.0 mL of sodium hydroxide solution to the titration dish using the volumetric pipette.
   d. Add 3 mL of barium chloride solution to the titration dish using the 3-mL syringe.

Warning: Barium chloride is extremely poisonous. Be sure to use a syringe, and not a pipette, to add the barium chloride solution to the titration dish.

e. Add 2 to 4 drops of phenolphthalein indicator solution while stirring the contents of the titration dish.

f. Titrate the mixture with the hydrochloric acid solution (using the 10-mL pipette) until the solution is colorless.

Note: If the pink color reappears, do not continue the titration.

g. Record the volume of hydrochloric acid solution needed to reach the endpoint as P_1.

4. Determine the P_2 alkalinity.

a. Add 25 mL of distilled water to a clean titration dish.

b. Repeat Steps 3c through 3f to determine P_2.

c. Record the volume of hydrochloric acid solution needed to reach the endpoint as P_2.

d. Calculate the concentration of hydroxyl (OH^-), carbonate (CO_3^{-2}), or bicarbonate (HCO_3^-) ions.

Concentration, mg/L			
Criteria	**OH^-**	**CO_3^{-2}**	**HCO_3^-**
$P_1 > P_2$	$340 (P_1 - P_2)$	$1,200 [P_f - (P_1 - P_2)]$	0
$P_1 = P_2$	0	$1,200 P_f$	0
$P_1 < P_2$	0	$1,200 P_f$	$1,220 (P_2 - P_1)$

Table 5-3: Concentration calculations. Use these calculations for hydroxide (OH^-), carbonate (CO_3^{-2}), and bicarbonate (HCO_3^-) ions in water-based drilling fluids.

BARACAT concentration

Objective

Determine the concentration of BARACAT in the filtrate of a CAT-I mud.

Unit

lb/bbl

Example

Excess BARACAT = 1.0 lb/bbl

Equipment

- DR/700 HACH Colorimeter with 610 nm Module
- 5-125 mL Erlenmeyer flasks
- 1-250 mL beaker
- 2-1 mL pipettes
- 2-5 mL pipettes
- 2-10 mL HACH sample cells
- Deionized water (DI water)
- Diethanolamine buffer (Dissolve 50 gm in 30 mL DI water then dilute to 100 mL).
- Hydroxyamine hydrochloride reagent (Dissolve 5 gm in 95 mL DI water).
- Indigo carmine solution [Dissolve 0.090 gm (analytically weighed) of Indigo carmine in DI water and dilute to 500 mL]. Store in a dark bottle.

Procedure

1. Preparation of standard curve
    a. Add 0, 1, 2, 4, and 6 lb/bbl equivalents of BARACAT to 350 mL samples of the base fluid.
    b. Add 100 mL of DI water to the 250 mL beaker.
    c. Add 2 mL of the standard solution.
    d. Using a clean 1-mL pipette, transfer 1 mL of the hydroxyamine reagent to the beaker.

e. Using a clean 5-mL pipette, transfer 5 mL of the buffer solution to the beaker.
f. Using a clean 5-mL pipette, transfer 5 mL of the Indigo carmine to the beaker.
g. Mix the contents of the beaker 2 to 3 minutes and allow to stand undisturbed for 15 minutes.
h. Fill a 10 mL HACH sample cell with DI water and zero the HACH meter (Consult the colorimeter meter manual for operating instructions).
i. Transfer 10 mL of the test fluid to a HACH sample cell and determine the absorbance of the test sample.
j. Determine the absorbance of each standard solution.
k. Prepare a standard curve by plotting absorbance versus lb/bbl BARACAT. (A new standard curve must be determined each time a new batch of reagent is prepared).

2. Testing of filtrate mud.
   a. Collect 2 mL of mud filtrate.
   b. Add 100 mL of DI water to the 250 mL beaker.
   c. Using a clean 1-mL pipette, transfer 0.2 mL of the filtrate to the beaker.
   d. Using a clean 1-mL pipette, transfer 1 mL of the hydroxyamine reagent to the beaker.
   e. Using a clean 5-mL pipette, transfer 5 mL of the buffer solution to the beaker.
   f. Using a clean 5-mL pipette, transfer 5 mL of the Indigo carmine solution to the beaker.
   g. Mix the contents of the beaker 2 to 3 minutes and allow to stand undisturbed for 15 minutes.
   h. Fill a 10 mL HACH sample cell with DI water and zero the HACH meter (Consult the colorimeter meter manual for operating instructions).
   i. Transfer 10 mL of the test fluid to a HACH sample cell and determine the absorbance of the test sample.

j. Determine the absorbance of the mud filtrate.

k. Plot the absorbance of the mud filtrate on the graph with the standard curve and interpolate the concentration of BARACAT in the filtrate.

BARACOR-95 concentration

Objective

Determine the concentration of BARACOR-95 in mud filtrate. If the filtrate is dark, a quantitative determination is not possible.

Unit

mg/L

Example

BARACOR-95 concentration = 2 lb/bbl

Equipment

- 2-15 mL clear glass vials w/closures
- 1-1 mL pipettes
- 2-5 mL pipettes
- Cupric sulfate solution: 8 gm $CuSO_4 \cdot 5H_2O$ dissolved in 1000 mL of water
- Borax buffer solution: 15 gm sodium borate decahydrate dissolved in 1000 mL water

Procedure

1. Collect 2 mL of mud filtrate.
2. Label the two vials A and B.
3. Using a 5-mL pipette, transfer 2 mL of the mud filtrate to each of the vials

4. Using a 5-mL pipette, transfer 5 mL of the borax buffer solution to each of the vials
5. Using the 1-mL pipette, place a 0.25 mL aliquot of cupric sulfate solution in vial B, cap and shake for several seconds.
6. Wait one minute and compare the clarity of the solution in vial A with that of vial B. If vial B has a haze compared with vial A, the end point is reached, go to step 9.
7. If the end point is not reached continue adding 0.25 mL aliquots, checking after each addition, until vial B has a haze compared with vial A, or until 3 mL of cupric sulfate solution has been added to vial A.
8. If no haze has appeared after 3 mL of cupric sulfate solution has been added to vial A, compare the color of vial A to the cupric sulfate solution. If it is blue there is a large excess of BARACOR-95 in the mud, it will become come progressively darker blue with each cupric sulfate addition. Continue the process until the endpoint is reached. If the color is not blue (the same color as the cupric sulfate solution) but turquoise, repeat the procedure using fresh borax buffer solution.
9. When the endpoint is reached, the lb/bbl of BARACOR-95 in the mud is equal to the milliliters of cupric sulfate added to vial A.

Brine clarity

Objective

Estimate the solids content in a completion/workover fluid by measuring brine turbidity.

Unit

Nephelometric turbidity unit (NTU)

Example

Brine clarity = 20 NTU

Equipment

- Calibration curve

  Note: Onsite measurement of solids content requires an instrument-specific calibration curve, which is generated by the laboratory using wellbore solids and completion brine. Contact the laboratory to obtain a site-specific calibration curve.

- 100-mL graduated cylinder
- Six to eight 500-mL sample bottles
- Six to eight 100-mL sample bottles
- Turbidimeter

  Note: Use the same turbidimeter that was used to generate the calibration curve. Calibrate the turbidimeter according to the manufacturer's standards.

- 200-mesh screen

Procedure

1. Collect a 100-mL fluid sample from each location of interest. Locations of interest might include one or more of the following:
   - Mixing plant at low-pressure line
   - Transport truck, after half the volume has flowed from the truck
   - Transport boat, before offloading
   - Rigsite tank at low-pressure line, if available

- Rigsite flow line
- Rigsite filtration sample

2. If large solids are present, allow the sample to stand until the solids float or settle (about 3 to 5 minutes). Then remove the solids as follows:

   a. Floating solids: Scoop the solids from the top of the liquid.

   b. Settled solids: Pour the clear liquid into a sample bottle, ensuring that settled solids are not transferred.

3. Pour the sample through the 200-mesh screen into a 100-mL graduated cylinder.
4. Measure the turbidity of the sample and record the NTUs.
5. Use the calibration curve to compare the NTUs to mg/L to estimate solids content.

Brine specific gravity (density)

Objective

Determine the weight per unit volume of a brine.

Note: Use this method for most fluids except those that are viscous and/or those that contain solids.

Unit

sg or lb/gal

Example

Brine sg = 1.2 (12.5 lb/gal)

Equipment

- Deaerator (optional)
- Glass cylinder
- Hydrometer

Caution: Do not drop the hydrometer; it may crack on contact with a hard surface.

Procedure

1. Collect a fluid sample.
2. To deaerate the fluid sample:
   - Allow the sample to stand 3 to 5 minutes while tapping gently on the cylinder.

   Or

   - Use the deaerator.
     a. Pour the fluid sample into the deaerator.
     b. Secure the top on the container.
     c. Agitate the sample while operating the vacuum pump.
     d. Continue until the hand-operated vacuum pump can no longer be pumped.
     e. Pull the release valve.
     f. Open the container.

3. Equilibrate the fluid at 70°F (21°C) or at the desired reference temperature.

   Note: If necessary, cool the sample in the refrigerator or pack the sample with ice.

4. Fill the glass cylinder with the fluid sample to within 1 to 2 inches of the top by pouring the sample slowly down the side of the cylinder.
5. Inspect the hydrometer to ensure that it is clean and dry.
6. Place the hydrometer carefully into the cylinder, allowing it to gently settle to the proper measurement level.

   Caution: Dropping the hydrometer too rapidly can wet the hydrometer above the proper measurement level and cause false readings.

7. Spin the hydrometer and record the reading at which the hydrometer rests.

   Note: Read the hydrometer scale at the bottom of the meniscus of the fluid in the cylinder. Because the walls of the glass cylinder are water-wet, the top of the fluid will have a curved surface (the meniscus). The correct hydrometer reading will be the one aligned with the bottom boundary of the meniscus, as viewed from the side of the cylinder.

8. Multiply the hydrometer reading (specific gravity) by 8.345 to convert it to density, lb/gal (sg × 8.345 = lb/gal).
9. Convert the sample density to the industry-standard reference density at 70°F (21°C).

$$D_c = D_m (1 + V_e [T_m - 70])$$

Where

D_c = Corrected density at 70°F (21°C)

D_m = Density at temperature in lb/gal

T_m = Temperature of sample tested, °F

V_e = Volume expansion factors (dimensionless)

Note: Refer to the following table for V_e factors.

Volume expansion (V_e) factors

V_e	Density, lb/gal (sg)	Brine
0.000349	9.0 (1.08)	NaCl
0.000406	9.5 (1.14)	NaCl
0.000280	12.0 (1.44)	NaBr
0.000333	9.0 (1.08)	$CaCl_2$
0.00030	9.5 (1.14)	$CaCl_2$
0.000289	10.0 (1.20)	$CaCl_2$
0.000260	10.5 (1.26)	$CaCl_2$
0.000240	11.0 (1.32)	$CaCl_2$
0.000239	11.5 (1.38)	$CaCl_2$
0.000271	12.0 (1.44)	$CaBr_2/CaCl_2$
0.000264	12.5 (1.50)	$CaBr_2/CaCl_2$
0.000257	13.0 (1.56)	$CaBr_2/CaCl_2$
0.000254	13.5 (1.62)	$CaBr_2/CaCl_2$
0.000253	14.0 (1.68)	$CaBr_2/CaCl_2$

(continued on next page)

Volume expansion (V_e) factors		
V_e	Density, lb/gal (sg)	Brine
0.000250	14.5 (1.74)	$CaBr_2/CaCl_2$
0.000250	15.0 (1.80)	$CaBr_2/CaCl_2$
0.000250	15.5 (1.86)	$ZnBr_2/CaBr_2/CaCl_2$
0.000251	16.0 (1.92)	$ZnBr_2/CaBr_2/CaCl_2$
0.000252	16.5 (1.98)	$ZnBr_2/CaBr_2/CaCl_2$
0.000254	17.0 (2.04)	$ZnBr_2/CaBr_2/CaCl_2$
0.000259	17.5 (2.10)	$ZnBr_2/CaBr_2/CaCl_2$
0.000264	18.0 (2.16)	$ZnBr_2/CaBr_2/CaCl_2$
0.000271	18.5 (2.22)	$ZnBr_2/CaBr_2/CaCl_2$
0.000278	19.0 (2.28)	$ZnBr_2/CaBr_2/CaCl_2$

Table 5-4: V_e factors. Use this table to determine V_e factors.

Carbonate concentration/ Garrett Gas Train (GGT)

Objective

Determine the concentration of soluble carbonates in a water-based fluid.

Unit

ppm

Example

Carbonate concentration = 800 ppm

Equipment

- Garrett Gas Train apparatus (see Figure 5-1)

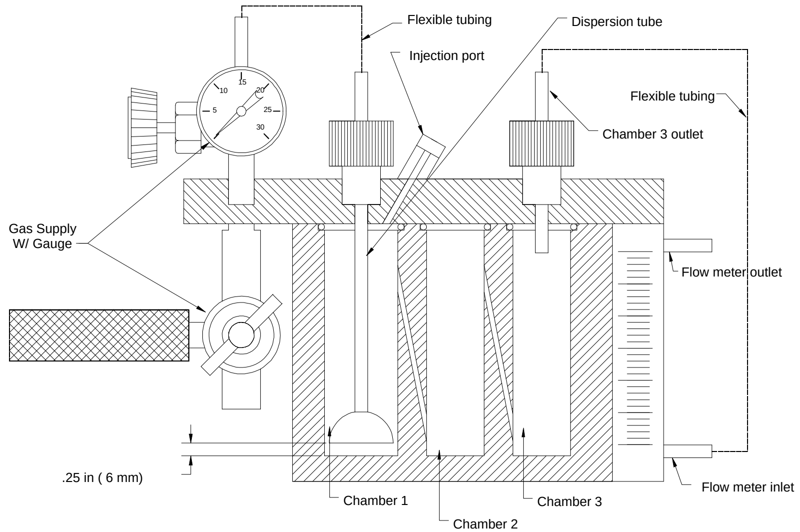

Figure 5-1: Garrett Gas Train apparatus. The Garrett Gas Train is used to help determine the concentration of soluble carbonates in a drilling fluid.

Note: Ensure the gas train is clean and dry, and that the regulator, tubing, and dispersion tube are purged of any carrier gas.

- CO_2 100/a Dräger analysis tube
- 1-liter Dräger Alcotest gas bag
- Hand-operated Dräger multigas detector vacuum pump
- Two-way bore stopcock
- 10-mL hypodermic syringe with a 1.5-inch (38-mm), 21-gauge hypodermic needle (to be used for acid)
- Syringe (1-, 5-, or 10-mL) with a 1.5-inch (38-mm), 21-gauge hypodermic needle (to be used for sample)
- Carrier gas

Note: Use either a nitrogen (N_2) bottle with a low-pressure regulator or nitrous oxide (N_2O) gas cartridges. N_2 is preferred because N_2O cools when it expands and chills the diaphragm in the regulator. This chilling can cause the regulator to perform erratically.

- 5N sulfuric acid, reagent grade
- Defoamer (in a dropper bottle)
- Distilled water

Procedure

1. Collect a filtrate sample using the API filtrate (LPLT) method.

2. Place the gas train on a level surface, remove the top of the gas train, and add the following to chamber 1:
   - 20 mL of distilled water
   - 5 drops of defoamer
3. Place the lid on the gas train and tighten it with a twisting motion so the O-rings seal the lid.
4. Adjust the dispersion tube so it is approximately 1/4 inch (5 mm) from the bottom.
5. Use the flexible tubing to connect the carrier gas supply to the dispersion tube on chamber 1.
6. Let the carrier gas flow through the gas train for approximately 1 minute to purge any air from the gas train.

   Note: As the carrier gas flows, check for leaks in the gas train.

7. Connect the stopcock and gas bag to the hand pump; then, depress and release the hand pump to check for leaks in the gas bag.

   Note: If the bag is free of leaks, the pump will remain depressed.

8. Connect the collapsed bag to the gas train by attaching flexible tubing from the bag's stopcock to the outlet on chamber 3.
9. Use a hypodermic syringe with needle to inject solids-free filtrate through the septum into chamber 1.

If the anticipated carbonate range is (ppm)...	Then the sample volume should be (mL)...
25-750	10.0
50-1500	5.0
250-7500	1.0

10. Inject 10-mL of sulfuric acid solution through the septum into chamber 1 using the 10-mL syringe and needle. Gently shake the gas train.
11. Open the stopcock on the gas bag and start a slow, steady gas flow.
12. Turn the gas flow off when the bag is firm, close the stopcock, and immediately break the tip off both ends of the Dräger tube.
13. Remove the tubing from the outlet on chamber 3 and place it on the upstream end of the Dräger tube, as indicated by the arrow on the Dräger tube.
14. Attach the other end of the Dräger tube to the hand pump.
15. Open the bag's stopcock. Depress and release the hand pump, counting the number of strokes it takes to fully deflate the bag.

    Note: If the number of strokes exceeds 10, suspect leakage and incorrect test results.

16. Observe the length of the purple stain (stain length) in the Dräger tube, including any peripheral blue tinge.

    Note: Test results are more accurate if the stain length runs at least half the tube length.

17. Calculate total soluble carbonates.

    Carbonate, ppm = 2.5 (stain length) ÷ sample volume, mL

Chloride content

Objective

Determine the chloride content of a water-based drilling fluid or completion/workover fluid.

Note: If bromide is present, it will show up as chloride using this test procedure.

Unit

mg/L

Example

Chloride = 15,000 mg/L

Equipment

- Titration dish
- 1-mL pipette
- 10-mL pipette
- Stirring rod
- Potassium chromate indicator solution
- 0.02N (N/50) sulfuric acid solution
- Phenolphthalein indicator solution
- Distilled water
- 0.0282N (1 mL = 0.001g Cl^-/mL) or 0.282N (1 mL = 0.01g Cl^-/mL) silver nitrate ($AgNO_3$) solution

If testing a...	Then use...
Freshwater system	0.0282N $AgNO_3$
Saltwater system	0.282N $AgNO_3$

Procedure

1. Collect filtrate sample using the API filtrate (LPLT) method.
2. Transfer 1 mL or more of filtrate to the titration dish. Note the color of the filtrate for Step 6.
3. Add 20 to 50 mL of distilled water to the filtrate in the titration dish.
4. Add 10 to 15 drops of phenolphthalein indicator solution.

If...	Then...
The color changes to pink or red,	Go to Step 5.
No color change is observed,	Go to Step 6.

5. Add the sulfuric acid solution slowly to the titration dish until the color changes from pink or red to the original color.
6. Add 5 to 10 drops of potassium chromate indicator solution.
7. Fill the 10-mL pipette with the silver nitrate solution.
8. Add the silver nitrate solution to the titration dish until the color changes from yellow to orange or orange-red.
9. Record the amount of silver nitrate solution used in mL.
10. Calculate the chloride content using the table below.

If using...	Then the mg/L chloride content is...
0.0282N $AgNO_3$	(1,000 × mL 0.0282N $AgNO_3$) ÷ mL filtrate
0.282N $AgNO_3$	(10,000 × mL 0.282N $AgNO_3$) ÷ mL filtrate

11. Calculate the concentration of salt in the fluid using the table below.

If the salt is...	Then the mg/L salt is...
Sea salt	1.804 × mg/L Cl^-
Sodium chloride (NaCl)	1.648 × mg/L Cl^-
Potassium chloride (KCl)	2.103 × mg/L Cl^-
Calcium chloride ($CaCl_2$)	1.565 × mg/L Cl^-

Note: Concentration of salt in lb/bbl can be calculated using the following formula:

$$lb/bbl\ salt = mg/L\ salt \times 3.505 \times 10^{-4}$$

12. Calculate brine sg (sg brine) using the table below.

If the salt is...	Then the sg brine is...
Sea salt	$0.998 + (1.359 \times 10^{-6})(mg/L\ Cl^-) - (1.643 \times 10^{-12})(mg/L\ Cl^-)^2$
Sodium chloride (NaCl)	$0.998 + (1.142 \times 10^{-6})(mg/L\ Cl^-) - (4.926 \times 10^{-13})(mg/L\ Cl^-)^2$
Potassium chloride (KCl)	$0.998 + (1.312 \times 10^{-6})(mg/L\ Cl^-) - (5.970 \times 10^{-13})(mg/L\ Cl^-)^2$
Calcium chloride ($CaCl_2$)	$0.998 + (1.243 \times 10^{-6})(mg/L\ Cl^-) - (3.715 \times 10^{-13})(mg/L\ Cl^-)^2$

13. Calculate the % by volume salt using the table below.

If the salt is...	Then the % by volume salt is (% by volume dissolved solids)...
Sea salt	[$7.368 \times 10^{-6} + 4.804 \times 10^{-7} \times$ (mg/L Cl^-) $+ 1.401 \times 10^{-12} \times$ (mg/L Cl^-)^2] $\times$ % by vol water
Sodium chloride (NaCl)	[$-3.025 \times 10^{-4} + 5.068 \times 10^{-7} \times$ (mg/L Cl^-) $+ 4.96 \times 10^{-13} \times$ (mg/L Cl^-)^2] $\times$ % by vol water
Potassium chloride (KCl)	[$-2.479 \times 10^{-4} + 7.922 \times 10^{-7} \times$ (mg/L Cl^-) $+ 6.011 \times 10^{-13} \times$ (mg/L Cl^-)^2] $\times$ % by vol water
Calcium chloride ($CaCl_2$)	[$-5.538 \times 10^{-4} + 3.181 \times 10^{-7} \times$ (mg/L Cl^-) $+ 3.795 \times 10^{-13} \times$ (mg/L Cl^-)^2] $\times$ % by vol water

CLAYSEAL Concentration

Objective

Determine the concentration of CLAYSEAL in a whole mud.

Unit

lb/bbl

Example

Concentration of CLAYSEAL = 0.75 lb/bbl (2.1 kg/m^3)

Equipment

- Hot plate
- Two 125 mL Erlenmeyer flasks
- Rubber stopper with glass tubing inserted through vent hole
- 1/8 inch glass tubing
- Flexible tubing
- 6 to 10 boiling stones

- 10 mL syringe
- Distilled water
- Silicone-based defoamer
- Indicator solution (1 part bromocresol green to 2 parts methyl red)
- 5N sodium hydroxide solution
- 2% boric acid solution
- 0.02N (N/50) sulfuric acid solution

Procedure

1. Prepare a 0.002N sulfuric acid solution by making a dilution of the 0.02N (N/50) sulfuric acid solution. (e.g. 10 mL of 0.02N (N/50) H_2SO_4 + 90 mL deionized water = 100 mL of 0.002 sulfuric acid solution)
2. Obtain a whole mud sample.
3. Add the following to the Erlenmeyer (reaction) flask
   - 25 mL of distilled water
   - 25 mL of sample to be tested
   - 2 mL of silicon-based defoamer
   - 6 to 10 boiling stones
   - 1/8 inch glass tubing
   - Flexible tubing

4. Add the following to the Erlenmeyer (collection) flask
   - 25 mL of 2% boric acid solution
   - 25 mL of deionized water
   - 10-15 drops of indicator solution
5. Place one end of the flexible tubing on the glass tubing into the collection flask.

Note: Ensure that the end of the glass tubing is submerged in the boric acid solution.

6. Attach the other end of the flexible tubing to the glass tubing in the stopper.
7. Use the 5 mL syringe to add 5 mL of the 5N sodium hydroxide to the reaction flask and immediately place the stopper on the flask.
8. Place the reaction flask on the hot plate and heat the solution to boiling.
9. Boil the solution for 45-55 minutes to distill at least 25 mL of solution into the collection flask.

Warning: If a ammonia odor is detected as the solution in the reaction flask boils, immediately stop the test and move to fresh air. An ammonia odor indicates leakage from the reaction flask.

Note: Maintain a constant boil or a vacuum might form, which will cause fluid to flow from the collection flask to the reaction flask.

10. Remove the glass tubing from the collection flask to thereaction flask.

11. Tritrate the solution in the collection flask with the 0.002N sulfuric acid solution (prepared in step 1) to the indicator endpoint. The color will change from blue/green to lavender/red.

12. Record the mL of sulfuric acid used.

13. Calculate the concentration of CLAYSEAL in lb/bbl using the following formula.

$$CLAYSEAL,\ lb/bbl = \frac{(V_{H_2SO_4})(25.35)}{V_{mud}}$$

Crystallization point

Objective

Determine the crystallization temperature of a high-density completion/workover fluid, including:

- First crystal to appear (FCTA)
- True crystallization temperature (TCT)
- Last crystal to dissolve (LCTD)

Unit

°F (°C)

Example

Crystallization point = 50°F (10°C)

Equipment

Note: Crystallization kit is available from FANN Instrument Company.

- Digital thermometer (-50 to 100°F [-46 to 38°C]) with thermometer probe
- 25 × 150-mm test tube
- 20 × 150-mm test tube
- Seeding material (e.g., calcium carbonate, diatomaceous earth)
- One or more of the cooling baths in the table below

  Note: The temperature of the cooling bath should be no more than 20°F (11°C) below the expected FCTA. Cool samples at a rate of no more than 1°F (0.5°C) per minute.

If anticipated FCTA is...	Then use...	Note
> 35°F (> 2°C)	Ice/water (50/50)	Cooling bath temperature will be 32°F (0°C).
> 10°F (> -12°C)	Ice/NaCl/water (50/50)	Cooling bath temperature will be about 5 – 10°F (-15 – 12°C). NaCl solutions should contain 30 g NaCl in 90 cm^3 water.

If anticipated FCTA is...	Then use...	Note
> -49°F (> -45°C)	Antifreeze/water (60/40) Ethylene glycol 37% *Note: 58.1 % volume = 50% weight*	Cooling bath is cooled by placing the bath container in a dry ice/acetone bath. The bath should be cooled to 15°F (9°C) below the expected FCTA.
> -40°F (> -40°C)	Ice/$CaCl_2$/water (50/50) *Note: 29.8% weight by volume $CaCl_2$*	Cooling bath will cool brine to -40°F (-40°C).

Procedure

1. Transfer 25 mL of the sample brine into the 20 × 150-mm test tube.
2. Add 0.03 g of seeding material to the brine.
3. Place the test tube containing the mixture into the 25 × 150-mm test tube; then, put the test tubes in the cooling bath.
4. Place the thermometer in the brine mixture and use the thermometer to slowly stir the mixture as it cools.
5. Record the following temperatures.
   - FCTA: The minimum temperature reached just before crystallization occurs.
   - TCT: The maximum temperature reached just after crystallization occurs.

Note: The brine will remain at the TCT temperature for about 10 to 20 seconds. If the temperature does not stabilize, suspect supercooling and retest using a cooling bath with a warmer initial temperature.

6. Take the tubes out of the bath and stir the mixture as it warms. Record the temperature of the brine just after all of the crystals have dissolved as the LCTD temperature.

7. Repeat the test at least three more times. The same sample can be used.

8. Record the average of three tests. If the first test is inconsistent with the remaining tests, do not include it in the average.

Density: Baroid mud balance

Objective

Measure the density of a drilling or completion/workover fluid with a Baroid mud balance.

Units

lb/gal, lb/ft^3, g/cm^3, lb/in^2/1,000 ft, sg

Example

Drilling fluid density = 12 lb/gal (1.44 g/cm^3) or (1.44 sg)

Equipment

- Baroid mud balance
- 1-qt (946 cm^3) graduated mud cup

- Thermometer: 32 to 220°F (0 to 104°C)

Procedure

1. Place the base stand or carrying case on a flat, level surface.
2. Collect a fluid sample.
3. Measure and record the temperature of the sample; transfer the sample to the mud balance cup.
4. Tap the side of the mud balance cup gently with the cup's lid to break out any trapped air or gas.

   Note: If trapped air or gas is present, use the pressurized fluid density balance to determine mud weight. The procedure for using the pressurized fluid density balance follows this procedure.

5. Place the lid on the mud balance cup with a twisting motion and make sure some of the test sample is expelled through the lid's vent hole.

   Note: Immersing the lid in the fluid sample helps ensure a better closing.

6. Seal the vent hole with a finger and clean the balance with water, base oil, or solvent. Wipe off any excess water, base oil, or solvent.
7. Fit the knife edge of the balance into the fulcrum and balance the assembly by moving the rider along the arm.

   Note: The balance is level when the line on the sight glass is centered across the bubble.

8. Record the density from the side of the rider nearest the balance cup (the arrow on the rider points to this side). Report the measurement to the nearest 0.1 lb/gal, 1 lb/ft^3, 0.01 g/cm^3, or 10.0 lb/in^2/1,000 ft.

Density: Pressurized mud balance Fann convertible density balance

Objective

Measure the density of a fluid with a pressurized mud balance.

Units

lb/gal, lb/ft^3, g/cm^3 (sg), lb/in^2/1,000 ft

Example

Drilling fluid density = 12 lb/gal (1.44 g/cm^3) or (1.44 sg)

Equipment

- Fann (convertible density balance)
- 1-qt (946-mL) graduated mud cup
- Thermometer: 32 to 220°F (0 to 104°C)

Procedure

1. Collect a fluid sample.
2. Place the base stand or the carrying case on a flat, level surface.
3. Measure and record the temperature of the sample, then transfer the sample to the balance cup, filling to between 1/4 and 1/8 inch of the top. Tap the side

of the cup several times to break up any entrained air or gases.

4. Place the lid on the cup with the check valve in the down or open position.

   Note: Some of the test sample may be expelled through the valve.

5. Rinse the pressurization port and balance with water, base oil, or solvent and dry.

6. Slide the cup housing over the balance cup from the bottom, aligning the slot with the balance arm. Screw the closure over the pressure lid and tighten as tight as possible by hand to insure the pressure lid is completely seated.

7. Fill the pressurization pump with the test sample.

8. Push the nose of the pump onto the pressure port of the lid.

9. Pressurize the sample cup by maintaining a downward force on the cylinder housing. At the same time, force the knob down, with 50-70 lbs of force and release cylinder housing. Remove the pump.

   Note: The check valve in the lid is pressure-actuated. When there is pressure in the cup, the check valve is pushed upward to the closed position.

10. Clean the mud from the outside of the balance cup and lid. Wipe off any excess water, base oil, or solvent.

11. Fit the knife edge of the balance into the fulcrum and balance the assembly by moving the rider along the arm.

    Note: The mud balance is level when the line at the sight glass is centered across the bubble.

12. Record the density from the side of the rider nearest the balance cup. Report the measurement to the nearest 0.1 lb/gal, 1 lb/ft^3, 0.01 g/cm^3, or 10.0 lb/in^2/1,000 ft.

13. Reconnect the empty plunger assembly and push downward on the cylinder housing to release the pressure inside the cup.

14. Remove the pressure lid being careful not to spill the sample, then pore out the sample. Clean and dry all of the parts of the balance as soon as possible.

Density: Pressurized mud balance Halliburton Tru-Wate Cup

Objective

Measure the density of a fluid with a pressurized mud balance.

Units

lb/gal, lb/ft^3, g/cm^3, lb/in^2/1,000 ft, sg

Example

Drilling fluid density = 12 lb/gal (1.44 g/cm^3) or (1.44 sg)

Equipment

- Halliburton Tru-Wate Cup (fluid density balance)
- 1-qt (946-mL) graduated mud cup
- Thermometer: 32 to 220°F (0 to 104°C)

Procedure

1. Collect a fluid sample.
2. Place the base stand or the carrying case on a flat, level surface.
3. Measure and record the temperature of the sample, then transfer the sample to the balance cup.
4. Place the lid on the cup with the check valve in the down or open position.

   Note: Make sure some of the test sample is expelled through the valve.

5. Pull the check valve to the closed position.
6. Rinse the cap and threads with water, base oil, or solvent and dry.
7. Tighten the threaded cap on the cup.
8. Fill the plunger assembly with the test sample.
9. Push the nose of the plunger onto the mating O-ring surface of the check valve.

10. Pressurize the sample cup by maintaining a downward force on the cylinder housing. At the same time, force the piston rod down.

    Note: The check valve in the lid is pressure-actuated. When there is pressure in the cup, the check valve is pushed upward to the closed position.

11. Clean the mud from the outside of the balance cup and lid. Wipe off any excess water, base oil, or solvent.

12. Fit the knife edge of the balance into the fulcrum and balance the assembly by moving the rider along the arm.

    Note: The mud balance is level when the line at the sight glass is centered across the bubble.

13. Record the density from the side of the rider nearest the balance cup. Report the measurement to the nearest 0.1 lb/gal, 1 lb/ft^3, 0.01 g/cm^3, or 10.0 lb/in^2/1,000 ft.

14. Reconnect the empty plunger assembly and push downward on the cylinder housing to release the pressure inside the cup.

Electrical stability

Objective

Measure the electrical stability of an oil-based or synthetic drilling fluid.

Unit

Volts (V)

Example

Electrical stability = 1,500 V

Equipment

- Fann model 23D electrical stability tester
- 12-mesh screen or Marsh funnel
- Thermometer: 32 to 220°F (0 to 104°C)
- Heating cup

Procedure

1. Collect a drilling fluid sample.
2. Pour the sample through the 12-mesh screen or Marsh funnel.
3. Use the heating cup to adjust the temperature of the fluid to 120°F (49°C).
4. Immerse the probe in the sample with the tester turned off. Ensure the fluid covers the electrode surfaces.
5. Stir the sample with the probe for 15 to 30 seconds.
6. Turn the electrical stability tester on and press the Test button to start the test.

Note: Do not move the probe during the test.

7. Record the voltage when the values in the display stabilize.

Filtrate: LTLP

Objective

Measure the filtrate volume and filter cake of a drilling fluid using the API filtrate (LPLT) method.

Unit

mL/30 min

Example

Filtrate = 4.3 mL/30 min

Equipment

- Filter press
- Filter paper
- 30-minute interval timer
- 25- or 50-mL graduated cylinder

Procedure

1. Collect a fluid sample.
2. Assemble the cell with the filter paper in place.
3. Pour the sample into the cell to within ½ inch (13 mm) from the top.

4. Set the cell into the frame; place and tighten the top on the cell.

5. Place a dry, graduated cylinder under the drain tube.

6. Close the relief valve and adjust the regulator so a pressure of 100 ± 5 psi (690 ± 35 kPa) is applied in 30 seconds or less.

7. Maintain the pressure at 100 ± 5 psi (690 ± 35 kPa) for 30 minutes.

8. Shut off the flow through the pressure regulator and open the relief valve carefully.

9. Report the volume of filtrate in the graduated cylinder to the nearest mL.

   Note: If using a half-area filter press, multiply the filtrate volume by 2.

10. Release the pressure, verify that all pressure has been relieved, and remove the cell from the frame.

11. Disassemble the cell and discard the mud.

12. Leave the filter cake on the paper and wash lightly with the base fluid to remove any excess mud.

13. Measure and report the thickness of the filter cake to the nearest 1/32 inch (1.0 mm).

Filtrate: HTHP

Objective

Measure the filtrate volume and filter cake of a drilling fluid using the high temperature/high pressure (HTHP) method.

Unit

mL/30 min

Example

Filtrate = 8.3 mL/30 min

Equipment

- Baroid 175- or 500-mL HTHP filter press

  Note: Use the Baroid 175 only with temperatures up to 300°F (149°C); use the Baroid 500 for temperatures higher than 300°F (149°C).

- Filter paper
- 30-minute interval timer
- Thermometer up to 500°F (260°C)
- 25- or 50-mL graduated cylinder
- High-speed mixer
- Gas supply (CO_2 or nitrogen)

Caution: Do not use nitrous oxide (N_2O) as a pressure source for this test. N_2O can detonate when under temperature and pressure in the presence of oil, grease, or carbonaceous materials. Use only carbon dioxide (CO_2) or nitrogen (N_2)!

Procedure

1. Collect a fluid sample.
2. Preheat the heating jacket to 10°F (6°C) above the desired test temperature.

   Note: If necessary, adjust the thermostat to maintain this temperature.

3. Close the bottom valve stem *on the filter cell* and pour a stirred, fluid sample into the cell.

   Note: Leave sufficient void space to allow for expansion of the mud.

If the temperature is °F (°C)...	Then the void space should be inches (cm)...
Up to 300 (149)	1 (2.5)
300-350 (149-177)	1.5 (3.8)
400-500 (204-260)	2.5-3.0 (6.3 - 7.5)

4. Place the filter paper in the cell.
5. Place the cap on the cell, tighten all set screws, and close the valve stem on the cap.

   Note: Apply Never-Seez® or an equivalent lubricant on the set screws to prevent the set screws from seizing in place.

6. Place the cell in the heating jacket with the cell cap on the bottom. Rotate the cell until it locks.

7. Put a thermometer in the cell thermometer well.

8. Connect the pressure unit to the top valve stem and lock the unit in place.

9. Connect the pressure receiver to the bottom valve stem and lock the receiver in place.

10. Apply 200 psi (1380 kPa) on the top and 100 psi (690 kPa) on the bottom.

11. Open the top valve stem and maintain this pressure until the desired test temperature is reached.

12. Open the bottom valve when the cell reaches the desired test temperature.

13. Adjust the pressure immediately on the top and bottom regulators. Use the following specifications as a guide.

If the temperature is °F (°C)...	**Then the top regulator should be set to (psi)...**	**And the bottom regulator should be set to (psi)...**
Up to 300 (149)	600	100
300-400 (149-204)	700	200
400-500 (204-260)	800	300

14. Filter for 30 minutes while maintaining the temperature at ± 5°F (± 3°C) of the test temperature and maintaining the pressure.

Caution: If the bottom pressure rises 20 psi (138 kPa) above the specified pressure during the test, cautiously bleed off pressure by draining a

portion of the filtrate from the receiver into a graduated cylinder.

15. Close the top and bottom valve stems.
16. Release the pressure off the top regulator and disconnect the pressure system.
17. Back off the T-screw on the bottom regulator.
18. Drain the filtrate cautiously from the receiver into a graduated cylinder.
19. Wait a few seconds for the filtrate to drain to the bottom of the receiver.
20. Tighten the T-screw slowly to flush any filtrate remaining in the receiver into the graduated cylinder.
21. Release the pressure off the bottom regulator and disconnect the pressure system.
22. Remove the cell from the heating jacket and allow the cell to cool.

Caution: The cell is extremely hot; therefore, remove it carefully from the heating jacket.

23. Hold the filter cell with the cap down and loosen the filter cell's valve stem to release pressure.
24. Close the valve stem when all the pressure has been released.
25. Hold the filter cell with the cap up and loosen the valve stem.

26. Loosen the set screws and remove the cap.
27. Remove and measure the filter cake to the nearest 1/32 inch (1.0 mm).
28. Record the HTHP filtrate as two times the filtrate volume collected.

Hardness: Calcium hardness

Objective

Determine the calcium-ion concentration in a water-based fluid.

Note: If zinc is present, it will show up as calcium using this test procedure.

Unit

mg/L

Example

Calcium concentration = 300 mg/L

Equipment

- Titration dish
- 5-mL pipette
- 1-mL pipette
- 50-mL graduated cylinder
- Total hardness titrating solution (THTS) in 2-, 20-, or 200-epm concentrations
- Calcium buffer solution
- CalVer II indicator powder

- Distilled water

Procedure

1. Collect a filtrate sample using the API filtrate (LPLT) method.
2. Add 20 to 50 mL of distilled water to the titration dish.
3. Add 5 drops of Calcium *buffer* solution.
4. Add 0.25 to 0.5 g of CalVer II *indicator* powder.

If...	Then...
A red or purple color develops,	Go to Step 5.
A blue color develops,	Go to Step 6.

5. Titrate with the THTS slowly until the color changes from red or purple to blue.
6. Transfer 1 mL or more of filtrate to the titration dish using a pipette.

If...	Then...
A red or purple color develops,	Go to Step 7.
The blue or gray color remains,	The mL of the THTS is zero. Go to Step 9.

7. Titrate with the THTS slowly until the color changes from red or purple to blue, gray, or green.

8. Record the volume of THTS required to titrate the filtrate to the endpoint.

9. Calculate the calcium concentration, mg/L.

If...	Then...
2-epm THTS was used,	(mL THTS × 40) / mL filtrate = mg/L hardness as calcium
20-epm THTS was used,	(mL THTS × 400) / mL filtrate = mg/L hardness as calcium
200-epm THTS was used,	(mL THTS × 4,000) / mL filtrate = mg/L hardness as calcium

Hardness: Total hardness

Objective

Determine the total hardness of a water-based drilling fluid.

Note: Divalent ions, such as magnesium, zinc, calcium, etc., will contribute to total hardness.

Unit

mg/L

Example

Total hardness = 80 mg/L as calcium

Equipment

- Titration dish
- Two 1-mL pipettes
- 50-mL graduated cylinder
- Distilled water

- Total hardness titrating solution (THTS) in 2-, 20-, 200-epm concentrations
- Versenate hardness buffer solution
- Versenate hardness indicator solution

Procedure

1. Collect a filtrate sample using the API filtrate (LPLT) method.
2. Add approximately 20 to 50 mL of distilled water to the titration dish.
3. Add 10 to 15 drops of Versenate hardness *buffer* solution to the titration dish.
4. Add 10 to 15 drops of Versenate hardness *indicator* solution to the titration dish.

If...	Then...
A red or purple color develops,	Go to Step 5.
A blue color develops,	Go to Step 6.

5. Titrate with the THTS slowly until the color changes from red or purple to blue.
6. Transfer 1 mL or more of filtrate to the titration dish using a pipette.

If...	Then...
A red or purple color develops,	Go to Step 7.
The blue color remains,	The mL of the THTS is zero. Go to Step 9.

7. Titrate with the THTS slowly until the color changes from red or purple to blue, gray, or green.

8. Record the volume of THTS required to titrate the filtrate to the endpoint.

9. Calculate the total hardness content, mg/L.

If...	Then...
2-epm THTS was used,	(mL THTS × 40) / mL filtrate = mg/L hardness as calcium
20-epm THTS was used,	(mL THTS × 400) / mL filtrate = mg/L hardness as calcium
200-epm THTS was used,	(mL THTS × 4,000) / mL filtrate = mg/L hardness as calcium

Iron content

Objective

Determine approximate iron (Fe^{+2}) content of brines.

Unit

ppm

Example

50 ppm

Equipment

- 1-mL volumetric pipette
- 25-mL volumetric flask
- 1N nitric acid solution
- 1N hydrochloric acid solution
- EM Quant strip
- Ascorbic acid

Procedure

1. Put 1 mL of brine in a 25-mL flask using a 1-mL pipette.
2. Add 1 mL of 1N nitric acid or 1N hydrochloric acid to the flask.
3. Add 10 to 19 mL of deionized water to the flask.
4. Stopper the flask and shake.
5. Add 2 level tablespoons of ascorbic acid to the flask.
6. Stopper the flask and shake.
7. Fill the flask to the scribe line with deionized water.
8. Stopper the flask and shake.
9. Wait 5 minutes for the iron contaminant to convert from a ferric (Fe^{+3}) to a ferrous (Fe^{+2}) state.

10. Insert the EM Quant strip into the brine preparation for 1 second.

11. Withdraw the strip and allow the indicator band color to develop for 15 to 60 seconds.

12. Compare the color of the exposed strip to the color chart on the EM Quant strip tube label; use the number associated with the color that best matches the developed strip.

13. Calculate the approximate iron content of the brine.

    Iron content, ppm = color chart number × 25.

Methylene blue test (MBT)

Objective

Determine the cation exchange capacity (CEC) and the equivalent bentonite concentration of a water-based drilling fluid or completion/workover fluid.

Unit

lb/bbl

Example

CEC = 5 meq/mL of fluid

Equivalent bentonite concentration = 25 lb/bbl (71 kg/m^3)

Equipment

- 250-mL Erlenmeyer flask
- 10-mL syringe (without needle)

- Two 1-mL pipettes
- 25-mL graduated cylinder
- Stirring rod
- Hot plate
- Distilled water
- Methylene blue solution (3.74 g/L; 1 mL = 0.01 meq)
- 3% hydrogen peroxide solution
- 5N sulfuric acid solution
- API filter paper

Procedure

1. Collect a fluid sample.
2. Add 10 mL of distilled water to the Erlenmeyer flask.
3. Transfer 1 mL of the fluid sample to the Erlenmeyer flask; swirl the flask to disperse the sample.
4. Add 15 mL of the hydrogen peroxide solution to the mixture.
5. Add 0.5 mL of the sulfuric acid solution to the mixture.
6. Place the flask on the hot plate, bring the mixture to a boil, and slow-boil the mixture for 10 minutes.

7. Remove the flask from the hot plate and dilute the mixture to 50 mL with distilled water. Allow the mixture to cool.

8. Add 0.5 mL of methylene blue solution to the mixture.

9. Agitate the contents of the Erlenmeyer flask for approximately 20 seconds.

10. Transfer a drop of the mixture onto the filter paper with the stirring rod.

If the drop...	Then...
Develops a blue halo,	Go to Step 11.
Does not develop a blue halo,	Repeat Steps 8 - 10.

11. Agitate the mixture for 2 minutes.

12. Transfer a drop of the mixture onto the filter paper with the stirring rod.

If the drop...	Then...
Develops a blue halo,	This is the endpoint. Go to Step 13.
Does not develop a blue halo,	Repeat Steps 8 - 12.

13. Record the volume of methylene blue solution used to reach the endpoint.

14. Calculate the methylene blue CEC.

CEC, meq/mL of the fluid = mL of methylene blue solution ÷ mL of fluid sample

15. Calculate the equivalent bentonite content.

$$\text{Equivalent bentonite content, lb/bbl} = 5 \times (CEC)$$

$$kg/m^3 = 14 \times (CEC)$$

pH: Paper method

Objective

Determine the pH of a water-based drilling fluid or completion/workover fluid using the paper method.

Note: If the amount of Cl^- in the fluid to be tested is above 10,000 mg/L, use the strip method to determine pH.

Unit

pH

Example

pH = 9.5

Equipment

- pH paper

Note: Make sure the pH paper range encompasses the expected pH of the sample.

Procedure

1. Collect a fluid sample.
2. Remove a 1-inch strip of indicator paper from the dispenser.

3. Place the indicator paper on the surface of the fluid sample.

4. Allow the paper strip to absorb the fluid from the sample until the paper changes color.

   Note: The time it takes the paper to absorb the fluid will vary from a few seconds to a few minutes.

5. Match the color of the paper with the chart on the side of the dispenser box.

If...	Then...
The color is off the chart and cannot be matched,	Repeat Steps 1 - 5 using a range of pH paper closer to the expected pH range.

6. Read and record the pH value.

pH: Strip method

Objective

Determine the pH of a water-based drilling fluid or completion/workover fluid using the strip method.

Unit

pH

Example

pH = 9.5

Equipment

- pH strips

Note: Make sure the pH strip range encompasses the expected pH of the sample.

Procedure

1. Collect filtrate from a fluid sample using the API filtrate (LTLP) method.
2. Immerse the end of a pH strip in the filtrate for 5 seconds.
3. Take the pH strip out of the fluid and wait 10 seconds.

   Note: Do not touch the wet part of the strip.

4. Compare the color change on the strip with the color table on the box of pH strips.

If...	Then...
The color is off the chart and cannot be matched,	Repeat Steps 1 - 4 using a range of pH strip closer to the expected pH range.

5. Read and record the pH value.

pH: Meter method

Objective

Determine the pH of a water-based drilling fluid or completion/workover fluid using the meter method.

Unit

pH

Example

pH = 9.5

Equipment

- pH meter with electrode
- Thermometer
- pH buffer solutions (pH 7 and pH 10)
- Distilled water

Procedure

1. Collect a fluid sample.
2. Allow the fluid sample and buffer solutions to reach ambient temperature.
3. Immerse a clean thermometer into the pH 7 buffer solution and measure the temperature.
4. Set the temperature control on the pH meter to match the temperature of the buffer solution.
5. Clean the probe with distilled water and blot dry with a soft, lint-free cloth.
6. Immerse the probe in the pH 7 buffer solution.

7. Allow the reading to stabilize.

8. Set the pH meter to display 7.00 using the *standardize* knob.

9. Rinse with distilled water and blot dry the probe.

10. Repeat Steps 6 and 7 substituting pH 10 buffer solution for pH 7 buffer solution.

11. Set the meter display to 10.00 using the *slope* adjustment knob.

12. Check the meter with the pH 7 buffer solution.

13. Rinse with distilled water and blot dry the probe.

14. Recheck the calibration by repeating Steps 6 through 10.

    Note: If the meter cannot be calibrated, replace the electrodes and start the procedure over using fresh buffer solutions.

15. Rinse with distilled water and blot dry the probe.

16. Immerse the probe in the sample to be tested and stir.

17. Stop the stirring (after 10-20 seconds) and wait for the reading to stabilize.

18. Record the pH to the nearest 0.1 unit.

PHPA concentration

Objective

Determine the concentration of PHPA in a whole mud, supernatant, or filtrate sample.

Unit

lb/bbl

Example

Concentration of PHPA = 0.75 lb/bbl (2.1 kg/m^3)

Equipment

- Hot plate
- Two 125-mL Erlenmeyer flasks
- Rubber stopper with glass tubing inserted through vent hole
- One-eighth inch glass tubing
- Flexible tubing
- 5-mL pipette
- 6 to 10 boiling stones
- 5-mL syringe
- Distilled water
- Silicone-based defoamer
- Indicator solution (1 part bromocresol green to 2 parts methyl red)
- 5N sodium hydroxide solution

- 2% boric acid solution
- 0.02N (N/50) sulfuric acid solution

Procedure

1. Prepare a standard curve by plotting known concentrations of PHPA for a minimum of four solutions. (See Figure 5-2.)
2. Obtain a fluid sample (whole mud, supernatant, or filtrate).
3. Add the following to the Erlenmeyer (reaction) flask.
   - 50 mL of distilled water
   - 10 mL of sample to be tested
   - 2 mL of silicone-based defoamer
   - 6 to 10 boiling stones
4. Add the following to the other Erlenmeyer (collection) flask.
   - 30 mL of 2% boric acid
   - 4 to 6 drops of indicator solution
5. Place one end of the flexible tubing on the glass tubing and place the glass tubing into the collection flask.

Note: Ensure that the end of the glass tubing is submerged in the boric acid solution.

6. Attach the other end of the flexible tubing to the glass tubing in the stopper.

7. Use the 5-mL syringe to add 5 mL of sodium hydroxide to the reaction flask and immediately place the stopper on the flask.

8. Place the reaction flask on the hot plate and heat the solution to boiling.

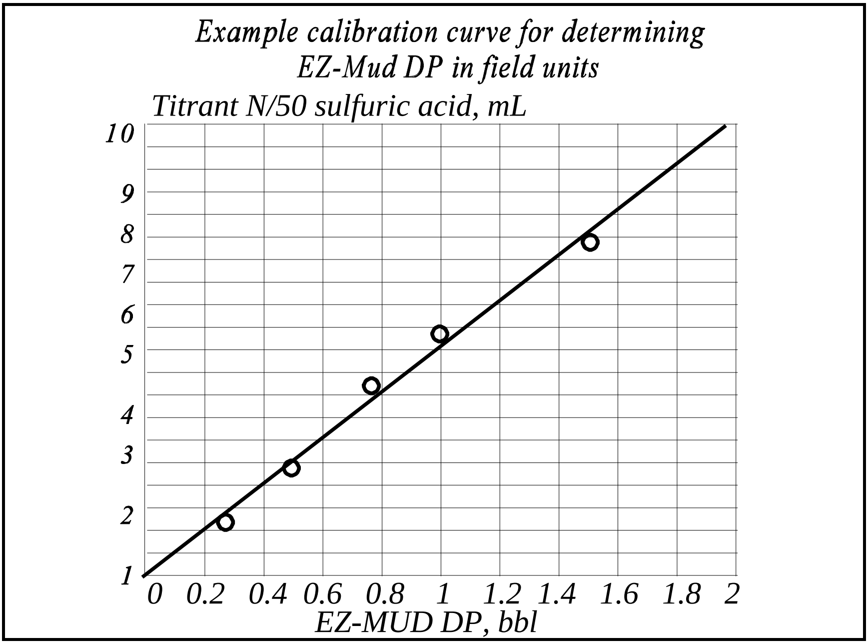

Figure 5-2: Example calibration curve. A calibration curve for determining PHPA in field muds plots sulfuric acid used (mL) versus PHPA (lb/bbl).

9. Boil the solution for 45 to 55 minutes to distill 25 mL of solution into the collection flask.

Warning: If an ammonia odor is detected as the solution in the reaction flask boils, immediately stop the test and move to fresh air. An ammonia odor indicates leakage from the reaction flask.

Note: Maintain a constant boil or a vacuum might form, which will cause fluid to flow from the collection flask to the reaction flask.

10. Remove the glass tubing from the collection flask and allow the flask to cool.

11. Titrate the solution in the collection flask with the sulfuric acid solution to the indicator endpoint. The color will change from blue/green to lavender/red.

12. Record the mL of sulfuric acid used.

13. Find the mL of sulfuric acid used (Y-axis) and the corresponding lb/bbl of PHPA (X-axis) using the standard curve graph created in Step 1.

Potassium: Strip method

Objective

Determine the potassium ion concentration of a water-based drilling fluid using the strip method.

Unit

mg/L

Example

Potassium ion concentration = 3,000 mg/L

Equipment

- Distilled water
- Potassium test kit

Caution: Do not let the reagent in the potassium test kit come in contact with skin or eyes and do not touch the reaction zone on the test strip.

Procedure

1. Collect a fluid sample.
2. Place the frosted (ignition) tube upright and add 10 drops of reagent to the ignition tube.
3. Dip the test strip in the fluid sample for 1 second. After removing the test strip, shake off any excess fluid.

   Note: Ensure all of the reaction zone on the test strip comes in contact with the fluid sample.

4. Put the test strip in the reagent for 1 minute.

   Note: When removing the test strip, wipe it clean using the inside edge of the ignition tube.

5. Compare the color of the reaction zone with the color scale provided.

If...	Then...
The color is off the chart and cannot be matched,	Dilute the fluid sample with distilled water and repeat Steps 2 - 5.

6. Read and record the potassium ion value.

7. Calculate the potassium ion concentration.

   Potassium ion concentration, mg/L = $K^+ \times$ *(mL of sample + mL of distilled water from dilution ÷ mL of sample)*

   Where

   K^+ = Potassium ion value from the color chart

Potassium: Centrifuge method

Objective

Determine the potassium chloride content of a water-based drilling fluid.

Unit

% by weight

Example

Potassium = 3% by weight of water phase

Equipment

- 100-mL volumetric flask
- 10-mL clinical centrifuge tube

Note: Use a Kolmer-type clinical centrifuge tube for this test. Do not use a substitute.

- Manual or electric centrifuge with a horizontal-swing rotor head
- Distilled water
- Standard sodium perchlorate solution (150 g in 100 mL of distilled water)

Warning: Dry sodium and potassium perchlorates are explosive when heated or when in contact with organic-reducing agents. The perchlorates are not hazardous if kept water-wet; they will decompose harmlessly if dispersed in a bucket of water and disposed of properly.

- Standard potassium chloride solution (14 g of dry KCl dissolved in distilled water and made up to 100 mL in a volumetric flask)
- Standard curve for potassium chloride

Procedure

1. Prepare a standard curve for potassium chloride (see Figure 5-3).

   Note: Recalibrate the standard curve when a new container (source) of sodium perchlorate is opened. Do not use the data in Figure 5-3 for your calculations.

   a. Prepare standards ranging from 10,000 to 80,000 mg/L KCl by adding standard potassium chloride solution (0.5 mL per 10,000 mg/L

KCl) to centrifuge tubes and diluting to the 7.0 mL mark with distilled water.

b. Add 3.0 mL of sodium perchlorate solution to each tube.

c. Centrifuge for 1 minute and immediately read the precipitate volume.

d. Plot milliliters of precipitate versus percent potassium chloride on the standard curve.

2. Collect a filtrate sample using the API filtrate (LTLP) method.

3. Measure 7.0 mL of filtrate into the centrifuge tube.

4. Add 3.0 mL of sodium perchlorate solution to the tube.

   Note: Precipitation occurs immediately.

5. Centrifuge for 1 minute and immediately read the precipitate volume.

   Note: Use the same centrifuge and sodium perchlorate solution used to construct the standard curve. Run the centrifuge at a constant speed of approximately 1,800 rpm.

6. Determine the potassium chloride concentration by comparing the precipitate volume measured with the standard curve for potassium chloride.

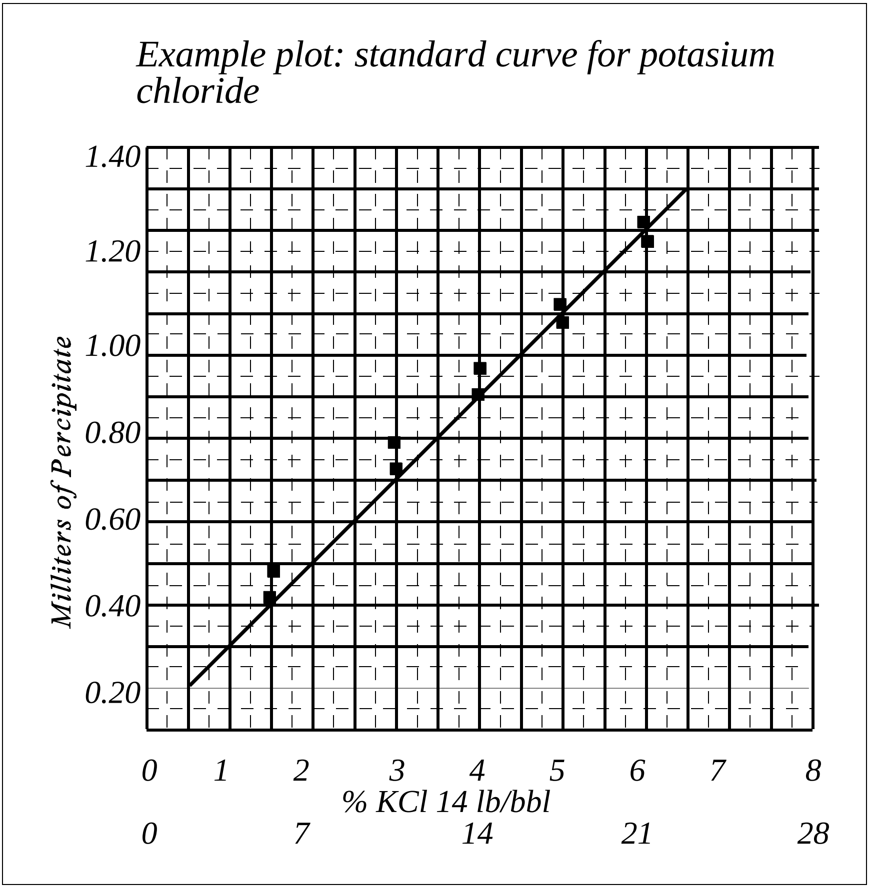

Figure 5-3: Example plot. A standard curve for potassium chloride plots millimeters of precipitate versus percent potassium chloride.

Retort analysis

Objective

Determine the liquid and solids content of a drilling fluid.

Unit

Percent by volume

Example

Liquid content % vol = 80%

Equipment

- Complete retort kit
- JP volumetric receiver
- Fine steel wool
- High temperature lubricant
- Pipe cleaners
- Putty knife or spatula with blade

Procedure

1. Collect a fluid sample and cool it to approximately 80°F (27°C).
2. Pack the upper retort chamber with very fine steel wool.

3. Lubricate the threads on the sample cup and condenser with a light coating of lubricating/antiseizing compound.

   Note: This will prevent vapor loss through the threads and also facilitate disassembly of the equipment and cleanup at the end of the test.

4. Fill the retort sample cup with gas-free mud.

   Note: Any trapped air will cause false readings.

5. Place the lid on the retort cup; rotate the lid slowly.

   Note: Make sure some of the test sample is expelled through the vent hole on the lid.

6. Wipe off any excess mud and screw the retort sample cup into the upper retort chamber.

7. Place the retort in the insulator block and put the insulator cover in place.

8. Place the volumetric receiver under the drain of the condenser.

9. Heat the sample until the liquid stops coming out through the condenser drain tube, or until the pilot light goes out on the thermostatically controlled units.

   Note: This usually takes 45 to 60 minutes.

10. Remove the volumetric receiver and examine the liquid recovered.

If...	Then...
Solids are in the liquid,	Whole mud has boiled over from the sample cup and the test must be repeated.
An emulsion band exists,	Warm the volumetric receiver slowly to 120°F (49°C).

11. Allow the volumetric receiver to cool to approximately 80°F (27°C).
12. Read and record the volumes of oil, or synthetic and water in the volumetric receiver.
13. Calculate % by volume of the liquid and solid components of the fluid.
    a. % by volume water = mL water × 10
    b. % by volume oil/synthetic = mL oil/synthetic × 10
    c. % by volume total solids = 100 - % by volume water - % by volume oil/synthetic
14. Calculate the oil:water (OWR) ratio or synthetic:water (SWR) ratio if the fluid is an oil-based or synthetic mud.

$$\text{Oil fraction} = 100 \times \frac{\text{\% by vol oil/synthetic}}{\text{\% by vol oil/synthetic} + \text{\% by vol water}}$$

Water fraction = 100 - oil/synthetic fraction

OWR = oil fraction:water fraction

SWR =synthetic fraction:water fraction

15. Calculate % by volume undissolved solids.

    % by vol undissolved solids = % by vol total solids - % by vol dissolved solids

    Note: For calculation of dissolved solids in oil-based or synthetic fluids, see the water-phase salinity calculations. For water-based fluids, see the chloride content calculations.

16. Calculate % by vol brine.

    % by vol brine = % by volume water + % by volume dissolved solids

17. Calculate average specific gravity of solids (ASG).

$$\text{ASG} = \frac{(\text{mud density, lb/gal})(11.98) - (\%\text{ by vol oil})(\text{sg oil}) - (\%\text{ by volume brine})(\text{sg brine})}{\%\text{ by volume undissolved solids}}$$

Note: For oil-based muds, see the water-phase salinity calculations for brine density sg. For water-based muds, see the chloride content calculations for brine sg.

18. Calculate % by volume low-gravity solids (LGS).

$$\%\,\text{LGS} = \frac{(\text{sg wt mtl} - \text{ASG})}{(\text{sg wt mtl} - \text{sg of the LGS})} \times 100$$

19. Calculate lb/bbl of LGS.

    lb/bbl LGS = % LGS × sg of the LGS × 3.505

20. Calculate % by volume high gravity solids (weight material).

    % by vol weight material = % by vol undissolved solids - % by vol LGS

21. Calculate lb/bbl weight material.

    lb/bbl high gravity solids (weight material) = % weight material × sg of the weight material × 3.505

Rheological properties: Marsh funnel

Objective

Use a Marsh funnel to obtain the funnel viscosity value of a drilling or completion/workover fluid.

Unit

sec/qt

Example

Funnel viscosity = 57 sec/qt

Equipment

- Marsh funnel
- 1-qt (946 cm^3) graduated mud cup
- Thermometer: 32 to 220°F (0 to 104°C)
- Stopwatch

Procedure

1. Collect a fluid sample.
2. Cover the funnel orifice with a finger and pour the fluid sample through the screen until the sample level reaches the underside of the screen.
3. Hold the funnel over the graduated mud cup.
4. Remove the finger covering the funnel orifice and simultaneously start the stopwatch.
5. Record the time it takes for 1 qt of sample to run out of the funnel as the Marsh funnel viscosity.

   Note: Record the time in seconds per quart. The time for 1 qt of clean, fresh water to run through the Marsh funnel at 70°F (21°C) is 26 seconds (± 0.5 seconds).

6. Measure and record the temperature of the fluid sample.

Rheological properties: Rotational viscometer

Objective

Determine viscometer readings to calculate the following for a drilling or completion/workover fluid:

- Plastic viscosity (PV)
- Yield point (YP)
- Gel strength
- Apparent viscosity (AV)
- Consistency index (K)
- Yield stress (YS)
- Flow index (n)

- Tau 0 (τ_0)

Unit

PV, centipoise (cP)

YP, lbf/100 ft^2 (kPa)

Gel strength, lbf/100 ft^2 (kPa)

Tau 0, lbf/100 ft^2 (kPa)

AV, centipoise (cP)

n [unitless]

K, lbf × sec^n/100 ft^2 (dyne × sec^n/cm^2, or eq cP)

YS, lbf/100 ft^2 (kPa)

Equipment

- Calibrated FANN concentric cylinder rotational viscometer
- Thermostatically controlled viscometer heater cup
- Thermometer: 32 to 220°F (0 to 104°C)

Procedure

1. Collect a fluid sample.
2. Place the sample in a thermostatically controlled viscometer cup.

   Note: Leave enough empty volume for the displacement of the bob and sleeve.

3. Immerse the viscometer rotor sleeve exactly to the scribed line.

4. Heat the sample to the selected temperature.

   Note: To obtain a uniform sample temperature, stir the sample at an intermittent or constant shear of 600 rpm while heating the sample.

5. Rotate the viscometer sleeve at 600 rpm until a steady dial reading is obtained. Record the dial reading ($\theta 600$).

6. Rotate the viscometer sleeve at 300 rpm until a steady dial reading is obtained. Record the dial reading ($\theta 300$).

7. Stir the sample for 10 to 15 seconds at 600 rpm, then let the mud stand undisturbed for 10 seconds.

8. Rotate the viscometer sleeve at 3 rpm until the maximum dial reading is obtained.

9. Record the maximum dial reading obtained as the 10-second gel strength, lbf/100 ft^2.

10. Restir the sample for 10 to 15 seconds at 600 rpm, then let the sample stand undisturbed for 10 minutes.

11. Rotate the viscometer sleeve at 3 rpm until the maximum dial reading is obtained.

12. Record the maximum dial reading obtained as the 10-minute gel strength, lbf/100 ft^2.

Formulas

PV, cP = θ600 - θ300 rpm

YP, $lbf/100\ ft^2$ = θ300 rpm - PV

AV, cP = θ600 rpm ÷ 2

n = log (θ600 ÷ θ300)

K, $lbf\ sec^n/100\ ft^2$ = 1.07 (θ300 ÷ 511^n)

Gel strength, $lbf/100\ ft^2$ = Max. dial reading at 3 rpm

YS, $lbf/100\ ft^2$ = (2 × θ3 rpm) - θ6 rpm

Note: The above calculation is for a standard viscometer.

Note: To calculate Tau 0, use Baroid's software program CFG+, DFG+ and DFG+ Win.

Sand content

Objective

Determine the sand content of a water-, oil-, or synthetic-based drilling fluid.

Unit

% by volume

Example

Sand = 0.25% by volume

Equipment

- Sand content tube

- Funnel that fits screen
- 200-mesh screen

Procedure

1. Collect a fluid sample.
2. Pour fluid into the sand content tube to the mud mark.
3. Add base fluid to the water mark.
4. Place a finger over the opening of the sand content tube and shake the tube vigorously.
5. Pour the contents of the sand content tube over the 200-mesh screen. Discard the fluid that passes through the screen.

   Note: If necessary, repeat Steps 3 through 5 until the sand content tube is clean.

6. Wash the sand on the screen carefully with base fluid to remove any remaining mud.
7. Place the wide end of the funnel over the top of the mesh screen and invert the screen and funnel slowly, turning the tip of the funnel into the mouth of the sand content tube.
8. Spray the screen with base fluid so that the sand on the screen falls into the tube.
9. Place the tube in a full upright position and let the sand settle.

10. Read the volume percent of sand in the sand content tube and report the sand content in percent by volume.

Silicate Concentration

Objective

Determine the concentration of SiO_2 and Na_2O and M_f/P_f in the filtrate of a BARASIL-S mud or the SiO_2 and K_2O and M_f/P_f concentration of a BARASIL-P mud.

Unit

mg/L

Example BARASIL-S

Alkalinity Na_2O =40,000 mg/L

Excess SiO_2 = 80,000 mg/L

Example BARASIL-P

Alkalinity K_2O =40,000 mg/L

Excess SiO_2 = 80,000 mg/L

Equipment

Titration dish

- Magnetic stirrer and stirrer bar
- 1-2 mL pipettes
- 1-10 mL pipettes

- Pipette Bulb filler
- Deionized water (DI water)
- 1N hydrochloric acid
- Sodium fluoride
- Methyl red indicator (1 gram of methyl red indicator in 1 liter of ethanol/water solution - 60/40 vol%)
- Phenolphthalein indicator solution

Procedure

1. Collect 2 mL of mud filtrate.
2. Add 10 mL of DI water to the titration dish.
3. Add 2 drops of Phenolphthalein indicator solution.
4. Using a 2-mL pipette, transfer 2 mL of the mud filtrate to the titration dish. Color will turn to pink.
5. Using a clean 10-mL pipette, titrate with the 1N HCl until the color changes from pink to colorless
6. Record the volume of 1N HCl required to titrate the filtrate to the end point. (Record as VP)
7. Add 2 drops of Methyl red indicator.
8. Using a clean 2-mL pipette, titrate with the 1N HCl until the color changes from yellow to pink. (Record and add to VP) Total vol = (VM)
9. Add 1 gram of sodium fluoride to the titration dish. The color will change to yellow.

10. Using a clean 2-mL pipette, titrate with the 1 N HCl until the color changes from yellow to pink, and color remains.

11. Record the volume of 1N HCl required to titrate the filtrate to the end point. (Record as V2)

Alkalinity Calculations

1. Na_2O, mg/L (BARASIL-S) = 15,500 (VP)

Where:

VP = Volume of 1N HCl (step 6)

2. K_2O, mg/L (BARASIL-P) = 23,500 (VP)

Where:

VP = Volume of 1N HCl (step 6)

Excess SiO_2 Calculations

1. SiO_2, mg/L (BARASIL-S or BARASIL-P) = 7,500 (V2)

Where:

V2 = Volume of 1N HCl (step 11)

P_f/M_f Calculations

1. P_f = VP x 25

2. M_f = VM x 25

Where:

VP = Volume of 1N HCl (step 6)

VM = Volume of 1N HCl (step 11)

Sulfide concentration/ Garrett Gas Train (GGT)

Objective

Determine the concentration of soluble sulfides in a water-based, oil-based, or synthetic drilling fluid.

Unit

ppm

Example

Concentration of sulfides = 100 ppm

Equipment

- Garrett Gas Train apparatus (see Figure 5-4)

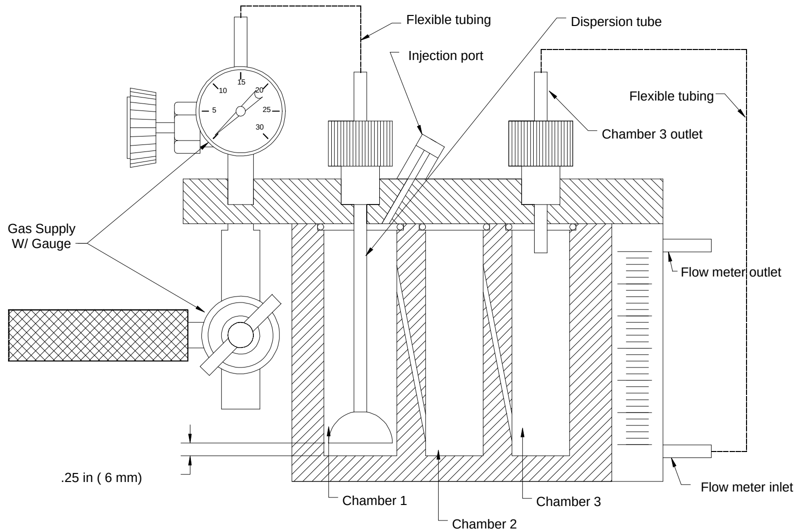

Figure 5-4: Garrett Gas Train apparatus. The Garrett Gas Train is used to help determine the concentration of soluble sulfides in a drilling fluid.

Note: Ensure the gas train is clean and dry, and that the regulator, tubing, and dispersion tube are purged of any carrier gas. In addition, use only latex rubber or inert plastic tubing.

For water-based drilling fluids

- Low-range H_2S 100/a Dräger analysis tube
- High-range H_2S 0.2%/A Dräger analysis tube
- 10-mL hypodermic syringe for acid
- 10-mL hypodermic syringe
- 5-mL hypodermic syringe
- 2.5-mL hypodermic syringe
- Three 1.5-in (38 mm), 21-gauge needles
- Carrier gas

Note: Use either a nitrogen (N_2) bottle with a low-pressure regulator or carbon dioxide (CO_2) gas cartridges.

- 5N sulfuric acid, reagent grade
- Octanol defoamer (in a dropper bottle)
- Lead-acetate paper disks (optional)

Note: A lead-acetate paper disk can be used instead of the Dräger tube to determine the presence of H_2S. The disk is placed under the O-ring of chamber 3. When a disk provides a positive indication of sulfide, the test should be repeated using a Dräger tube so that a quantitative analysis can be made.

- Distilled water

For oil-based and synthetic drilling fluids

- 20 mL of citric acid/de-emulsifier/isopropyl alcohol solution

  a. Prepare a 2M citric acid solution by dissolving 420 g reagent-grade citric acid in distilled water to make 1,000 mL of solution.

  b. Mix 200 mL of isopropyl alcohol and 25 mL of Exxon’s Corexit 8546 de-emulsifier or equivalent into 100 mL of the 2M citric acid solution.

- Magnetic stirrer with a 1-inch (2.5 cm) stirring bar coated with glass or Teflon®, or equivalent
- Injection tube with Luer-Lok®

Procedure for water-based muds

1. Place the gas train on a level surface and remove the top of the gas train.
2. Add the following to chamber 1:
   - 20 mL of distilled water
   - 5 drops of defoamer
3. Determine which Dräger tube to use.

   Note: Tube factor of 0.12 applies to H_2S 100/a Dräger tubes that are marked for a 100 to 2,000

range. For older H_2S 100/a tubes (those marked from 1 to 20), a tube factor of 12 applies.

If the anticipated sulfide range is (ppm)...	Then use Dräger tube H_2S...
1.2-24	100/a (tube factor 0.12)
1.5-48	100/a (tube factor 0.12)
4.8-96	100/a (tube factor 0.12)
60-1020	100/a (tube factor 0.12)
120-2040	0.2%/A (tube factor 600*)
240-4080	0.2%/A (tube factor 600*)
* *The tube factor of 600 is based on a batch factor of 0.40. If the batch factor is different for the tube used, as indicated on the box the tube came in, then correct the tube factor using the following calculation: Tube factor = 600 (batch factor) ÷ 0.40.*	

4. Place the top back on the gas train and tighten the top so the O-rings are sealed.
5. Adjust the dispersion tube so it is approximately 1/4 inch (5 mm) from the bottom.
6. Use the flexible tubing to connect the carrier gas supply to the dispersion tube on chamber 1.
7. Connect chamber 3 to the inlet of the flowmeter using the flexible tubing.
8. Connect the Dräger tube to the outlet port of the flowmeter using the flexible tubing.

   Note: Break tips off both ends of the Dräger tube before installing it.

9. Flow the carrier gas through the gas train for approximately 1 minute to purge any air from the gas train. As the carrier gas flows, check for leaks in the gas train.

10. Shut off the carrier gas after purging is complete.

11. Collect enough solids-free filtrate to analyze the concentration of soluble sulfides.

If the anticipated sulfide range is (ppm)...	Then sample volume should be (mL)...
1.2-24	10.0
1.5-48	5.0
4.8-96	2.5
60-1020	1..0
120-2040	5.0
240-4080	2.5

Note: Ensure the sample is not exposed to the air for long periods of time; sulfides are rapidly lost due to air oxidation.

12. Use a hypodermic syringe with needle to inject solids-free filtrate through the septum into chamber 1.

13. Inject 10 mL of sulfuric acid with the hypodermic needle through the septum into chamber 1.

14. Start a slow, steady gas flow immediately. Maintain the flow rate between 0.2 and 0.4 liters per minute (0.3 liters per minute is ideal) for 15 minutes.

Note: A CO_2 cartridge provides about 15 to 20 minutes of flow.

15. Observe the Dräger tube as the gas flows. Record the maximum darkened length in units, as read from the Dräger tube, before the front edge starts to smear.

    Note: If using the high-range tube, sulfites (SO_2) may cause a region of orange color. Do not include this orange region when recording the maximum darkened length.

16. Calculate total soluble sulfides.

    GGT Sulfides, ppm = Maximum darkened length × tube factor ÷ Sample volume, cm^3

Procedure for oil-based and synthetic muds

1. Set the Garrett gas train body, with the top removed, on the magnetic stirrer with the center of chamber 1 over the center of the stirrer. Place the stirring bar in chamber 1.

   Note: Remove the rubber feet from the Garrett gas train so it will rest flat on the stirrer.

2 Add 20 mL of citric acid/de-emulsifier/isopropyl alcohol solution to chamber 1.

3. Determine which Dräger tube to use.

   Note: Tube factor of 0.12 applies to H_2S 100/a Dräger tubes that are marked for a 100 to 2,000

range. For older H_2S 100/a tubes (those marked from 1 to 20), a tube factor of 12 applies.

If the anticipated sulfide range is ppm...	Then use Dräger tube H_2S...
1.2 - 24	100/a (tube factor 0.12)
1.5 - 48	100/a (tube factor 0.12)
4.8 - 96	100/a (tube factor 0.12)
60 - 1020	100/a (tube factor 0.12)
120 - 2040	0.2%/A (tube factor 600*)
240 - 4080	0.2%/A (tube factor 600*)

* *The tube factor of 600 is based on a batch factor of 0.40. If the batch factor is different for the tube used, as indicated on the box the tube came in, then correct the tube factor using the following calculation: Tube factor = 600 × batch factor ÷ 0.40.*

4. Replace the top on the gas train and tighten the top so that the O-rings are sealed.
5. Adjust the dispersion tube in chamber 1 so that it is approximately 1/4 inch (6 mm) above the liquid level.
6. Use the flexible tubing to connect the carrier gas supply to the dispersion tube on chamber 1.
7. Connect chamber 3 to the inlet of the flowmeter using the flexible tubing.
8. Connect the Dräger tube to the outlet port of the flowmeter using the flexible tubing.

Note: Break tips off both ends of the Dräger tube before installing it.

9. Flow the carrier gas through the gas train for approximately 1 minute to purge any air from the gas train. As the carrier gas flows, check for leaks in the gas train.

Caution: Do not use nitrous oxide (N_2O) as a carrier gas for this test. N_2O can detonate when under temperature and pressure in the presence of oil, grease, or carbonaceous materials. Use only carbon dioxide (CO_2) or nitrogen (N_2)!

10. Shut off the carrier gas after purging is complete.
11. Turn on the magnetic stirrer. Adjust its speed until a vortex is formed in the liquid.
12. Lower the gas dispersion tube into the liquid to a point just above the rotating stirring bar to allow the oil mud to enter the vortex.
13. Inject the whole mud sample with a syringe through the injection tube into chamber 1.

If the anticipated sulfide range is (ppm)...	Then the sample volume should be (mL)...
1.2 - 24	10.0
1.5 - 48	5.0
4.8 - 96	2.5
60 - 1020	1.0
120 - 2040	5.0
240 - 4080	2.5

14. Increase the stirrer speed to improve dispersion and to prevent oil mud from sticking to the walls of chamber 1.

15. Start a slow, steady gas flow immediately. Maintain the flow rate between 0.2 and 0.4 liters per minute (0.3 liters per minute is ideal) for 15 minutes.

    Note: A CO_2 cartridge provides about 15 to 20 minutes of flow.

16. Observe the Dräger tube as the gas flows. Record the maximum darkened length in units read from the Dräger tube, before the front edge starts to smear.

    Note: When using the high-range tube, sulfites (SO_2) may cause a region of orange color. Do not include this orange region when recording the maximum darkened length.

17. Calculate total soluble sulfides.

    GGT sulfides, ppm = Maximum darkened length × tube factor ÷ Sample volume, mL

Water-phase salinity

Objective

Determine the water-phase salinity of an oil-based or synthetic drilling fluid sample.

Unit

ppm, mg/L

Example

Water-phase salinity = 250,000 ppm $CaCl_2$ (307,000 mg/L)

Equipment

- 10-mL syringe
- 1-mL pipette
- Two 5-mL pipettes
- Magnetic stirrer with 1.5-inch (38-mm) coated stirring bar
- Hamilton Beach® mixer or Multimixer® with cup
- Titration dish
- AKTAFLO-E nonionic surfactant
- Distilled water
- Arcosol PNP solvent or base fluid
- Calcium buffer solution and CalVer II indicator powder

Note: Keep the Calcium buffer solution in a closed, sealed bottle to minimize absorption of CO_2 from the air.

- Potassium chromate indicator solution
- 0.0282N silver nitrate titrating solution (1 mL is equivalent to 0.001 g Cl)
- 0.01 molar EDTA standardized or total hardness titrating solution (1 mL = 20 epm calcium)

Procedure

1. Use a 10-mL syringe to transfer 10 mL of the fluid to be tested into a stirring cup.
2. Add 20 mL of Arcosol PNP solvent or base fluid to the 10 mL of mud and mix thoroughly.
3. Add 20 mL of AKTAFLO-E and 200 mL of distilled water to the mixture.
4. Mix on a Multimixer or a Hamilton Beach mixer for 5 minutes.
5. Determine the calcium chloride content.
   a. Add 50 mL of distilled water to a titration dish.
   b. Add 10 to 15 drops of Calcium buffer solution and a pinch of CalVer II indicator powder to the 50 mL of distilled water.

If...	Then...
A wine-red color develops,	Titrate to the blue endpoint with total hardness titrating solution (1 mL = 20 epm).

Note: Do not include this volume of titrating solution in calculating the calcium chloride content. This part of the test removes calcium from the distilled water and is done for calibration purposes only.

c. Add 1.0 or more mL of the mud/solvent/ AKTAFLO-E emulsion into the titration dish.

d. Titrate to the endpoint with the total hardness titrating solution (1 mL = 20 epm).

Note: The chemical reaction of calcium ions with EDTA (hardness titrating solution active component) is very slow. There may be an initial color change to blue while titrating for calcium, but the color may revert to the violet/purple color after a few seconds. This is not the endpoint. The endpoint is reached when the color change from purple or violet to blue or blue-green remains stable for at least 1 minute. Continue intermittent additions of hardness titrating solution until this endpoint occurs.

e. Record the total volume of total hardness titrating solution (THTS) used to reach the endpoint.

6. Determine the sodium chloride content.

a. Add 50 mL of distilled water to a titration dish.

b. Add 10 to 15 drops of potassium chromate indicator.

c. Add 1.0 or more mL of mud/solvent/ AKTAFLO-E emulsion to the titration dish.

d. Titrate with silver nitrate solution (1 mL is equivalent to 0.001 g Cl^- ion) to the first color change (from yellow to orange, not brick red).

e. Record the volume of silver nitrate used.

7. Calculate concentrations of calcium chloride and sodium chloride, using the following methods.

Where

L	=	lime, lb/bbl of mud
r	=	Retort water fraction (decimal equivalent)
THTS	=	mL of total hardness titrating solution
SN	=	mL of silver nitrate solution

a. Calculate lb/bbl calcium chloride ($CaCl_2$) using the calcium titration (C_{Ca}).

If...	Then...
L 1,	C_{Ca}, lb/bbl = (9.73)(THTS/mL emulsion) - (1.5 L)
L > 1,	C_{Ca}, lb/bbl = (9.73)(THTS/mL emulsion) - 1.5

b. Calculate lb/bbl $CaCl_2$ using the chloride titration (C_{Cl}).

$$C_{Cl}\text{, lb/bbl} = (13.72)(\text{SN/mL emulsion})$$

c. Determine actual lb/bbl $CaCl_2$ (C).

If...	Then...
$C_{Ca} > C_{Cl}$,	C, lb/bbl = C_{cl} sodium chloride (NaCl), lb/bbl = 0
$C_{Ca} < C_{Cl}$,	C, lb/bbl = C_{ca} calculate NaCl, lb/bbl

d. Calculate lb/bbl maximum soluble $CaCl_2$ (C_{Max}).

$$C_{Max}\text{, lb/bbl} = 233\ r$$

e. Determine lb/bbl soluble $CaCl_2$ (C_{Sol}).

If...	Then...
$C < C_{Max}$,	C_{Sol}, lb/bbl = C
$C \geq C_{Max}$,	C_{Sol}, lb/bbl = C_{Max}; C - C_{Max} = insoluble $CaCl_2$, lb/bbl; soluble NaCl, lb/bbl = 0

f. Calculate lb/bbl NaCl using the chloride titration (N_{Cl}) .

$$N_{Cl}\text{, lb/bbl} = (14.45\ \text{SN/mL emulsion}) - 1.05\ C_{Sol})$$

g. Calculate lb/bbl maximum soluble NaCl (N_{Max}).

$$N_{Max}, lb/bbl = r[124.83 - (0.843 \times C_{Sol}) - (0.00329 \times C_{Sol}^{2}) + (0.0000438 \times C_{sol}^{3}) - (0.000000103 \times C_{Sol}^{4})]$$

h. Determine lb/bbl soluble NaCl (N_{Sol}).

If...	Then...
$N_{Cl} < N_{Max}$,	N_{Sol}, lb/bbl = N_{Cl}
$N_{Cl} \geq N_{Max}$,	N_{Sol}, lb/bbl = N_{Max}; $N_{Cl} - N_{Max}$ = insoluble NaCl, lb/bbl

i. Calculate mg/L whole mud chlorides (Cl_{OM}).

$$Cl_{OM}, mg/L = 25{,}000\ SN/mL\ emulsion$$

j. Calculate lb/bbl total soluble salts (T).

$$T, lb/bbl = C_{Sol}, lb/bbl + N_{Sol}, lb/bbl$$

k. Calculate water-phase salinity (WPS).

Water phase salinity (WPS) =

$$[1 \div (1 + 350 \times r/T)] \times 10^{6}$$

Note: Use the following salinity charts if calculating water-phase salinity is not a practical option.

l. Calculate brine density.

$$Brine\ sg,\ g/cc = 0.99707 + 0.7923\ (WPS\ \ x\ 10^{-6}) + 0.4964\ (WPS\ \ x\ 10^{-6})^2$$

m. Calculate volume of brine.

$$\%\ \ by\ volume\ brine\ (V_b) = (r\ x\ 100)\ \div [sg\ x\ (1 - (WPS\ \ x\ 10^{-6}))]$$

n. Calculate volume of salt (dissolved solids).

$$\%\ \ by\ volume\ dissolved\ salts\ (DS) =$$

$$V_b - (r\ x\ 100)$$

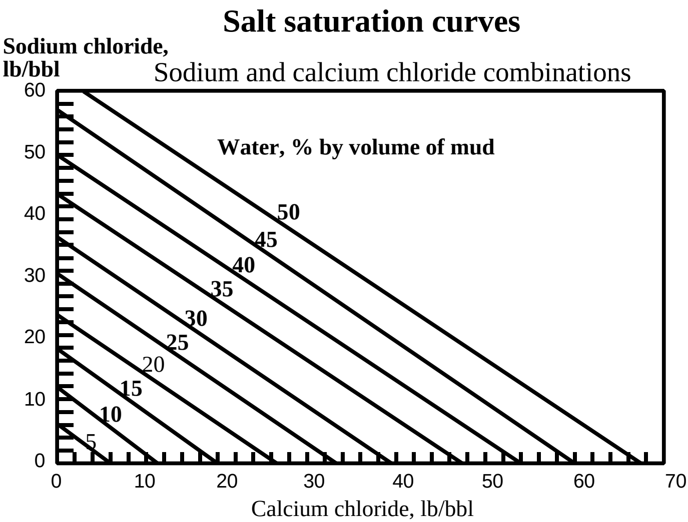

Figure 5-5: Salt saturation curves. Use these salt saturation curves to determine $NaCl_{Max}$.

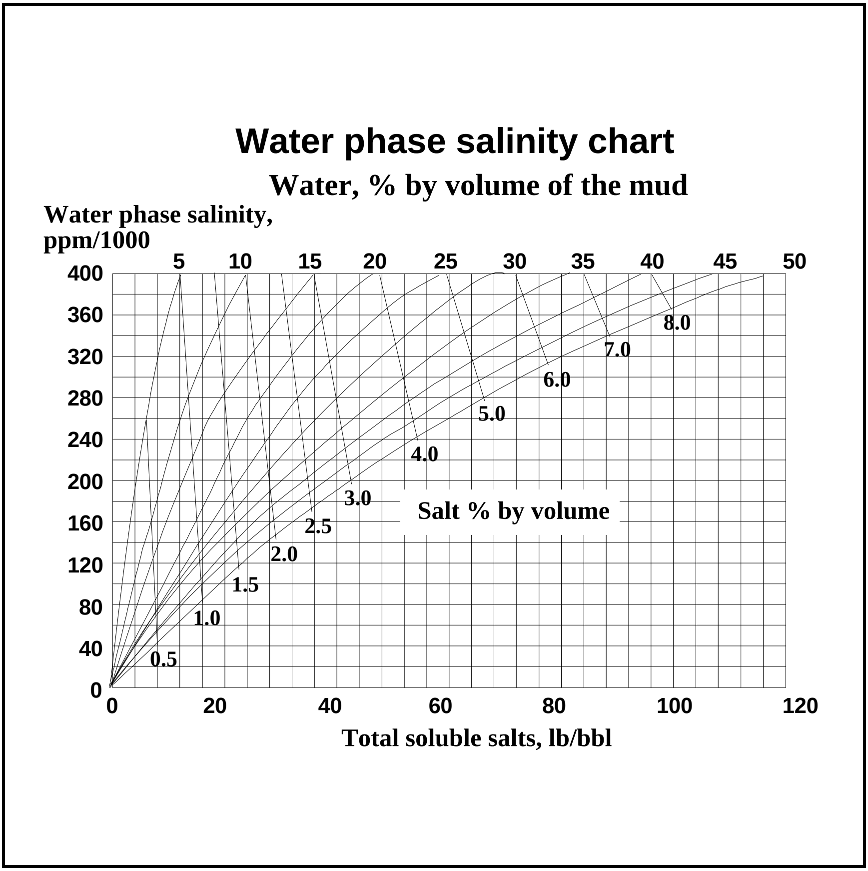

Figure 5-6: Water-phase salinity chart. Use this water-phase salinity chart to determine salt percent by volume.

CHAPTER

6

Foam and aerated mud drilling

The Complete Fluids Company

Contents

Overview

This chapter provides information and operational guidelines for air, foam, and aerated mud drilling systems. Common formulas are listed for some of the most popular muds. In addition, a section on corrosion explains how to avoid severe corrosion problems with the different mud systems.

Applications for air, foam, and aerated muds

In situations where normal drilling fluids are not appropriate, air, foam, and aerated muds are effective alternatives. These fluids can be used when drilling the following formations:

- Extremely porous formations
- Subnormally pressured formations
- Cavernous formations

Table 6-1 explains how each fluid is used.

Drilling fluid	Description	Application
Air/gas	• Air/gas is the continuous phase. • Large volumes of air/gas are required.	• Extremely low formation pressure • No water-bearing formation exposed
Foam	• A mixture of water or polymer slurry and foaming agents is added to compressed air.	• Larger annular spaces than air drilling • Water-bearing formations exposed
Aerated mud	• Drilling fluid is the continuous phase. • Air is added to reduce the hydrostatic pressure.	• Weak formations • Unstable formations with subnormal pressures (6 to 8 lb/gal EMW) (0.72-0.96 sg)

Table 6-1: Air, foam, and aerated mud drilling fluids. This table describes each type of fluid and provides recommended applications.

Air drilling uses air volume to drill formations that present major problems for drilling fluids. Foam is a combination of water or polymers/bentonite slurry mixed with a foaming agent; air from a compressor combines with the foaming agent to form the bubbles that act as carrying agents for cuttings removal. Aerated mud can be virtually any water-based mud to which air is added. This type of mud has less hydrostatic pressure and less tendency to fracture weak formations. Foam and aerated muds are useful in situations where air drilling is not possible and drilling fluids are not efficient.

Air drilling

Air drilling uses compressed gas for hole cleaning. Air is the most commonly used gas, but natural gas and other gases can also be used.

Problems that can be encountered with gas drilling include:

- Regulation of gas pressure
- Influxes of formation fluids
- Erosion of the wellbore

As the stream of gas and cuttings erodes the wall and widens the annulus, a greater increase in gas volume is required to maintain gas velocity. Sometimes water or mud is misted into the well to inhibit shales and reduce torque and drag.

The most important aspect of gas drilling is to maintain an adequate annular velocity. If the annular velocity falls below the point where it can clean the hole, the cuttings will accumulate and cause stuck pipe. An annular velocity of 3,000 ft/min is normally required for air drilling.

A useful reference for air and gas drilling is "Volume Requirements for Air and Gas Drilling" by R.R. Angel, Gulf Publishing Company. This small handbook contains charts showing volume requirements for various hole size combinations and penetration rates for both natural gas and air.

Foam drilling

Foam drilling uses foam as the carrying agent for cuttings removal instead of air velocity. Foam drilling requires less volume than air drilling and relies on bubble strength to remove cuttings, while air and mist drilling depend on extremely high flow rates. An indication of effective foam drilling is a continued and regular flow of foam at the blooey line. A pulsating, irregular flow (heading) can indicate problems with the flow columns. In addition to hole cleaning, the foam deposits a thin filter cake on the walls of the hole to improve borehole stability. To thicken foam and improve hole cleaning and water tolerance, polymers and/or bentonite are used to mix a slurry for injection.

Determining air and fluid volumes

In foam drilling, the injected air controls the amount of foam. Air volume requirements are calculated using the following formula:

$$\text{Velocity in ft/min} = \frac{(183.4)\,\text{cfm}}{D_h^2 - D_p^2}$$

Where

D_h = diameter of the wellbore in inches

D_p = diameter of the drillpipe in inches

cfm = cubic feet per minute

Controlling the foam drilling fluid

During the drilling operation, changes to foam injection rates are made based on:

- Changes in the character of the foam at the blooey line
- Changes in torque
- Changes in pressure

Surface injection pressure

Foam drilling is most effective when the lowest possible standpipe pressure is maintained. Pressure on the standpipe can range from 80 to 350 psi. Changes in the standpipe pressure are the best means of detecting problems. As pressure changes are identified, adjust the foam injection rate and the gas volume percentage to deal with the change. Table 6-2 provides corrective adjustments for different types of pressure changes.

Pressure change	Probable cause	Treatment
Quick drop	The gas has broken through the foam mix, preventing the formation of stable foam.	Increase the liquid injection rate and/or decrease the air injection rate.
Slow, gradual increase	There is an increase in the amount of cuttings or formation fluid being lifted to the surface.	Increase the gas/air injection rates slightly.
Rapid increase	The bit is plugged or the formation is packed off around the drillpipe.	Stop drilling and attempt to regain circulation by moving the drillpipe.

Table 6-2: Surface injection-pressure adjustments. Use these guidelines to manage the foam-drilling system.

Condition of foam at the blooey line

Under normal drilling conditions, foam at the blooey line should be similar in appearance and texture to shaving-cream foam. If the foam is not thick or does not

hold its shape, adjust the rates of gas and foam-solution injection. Consult Table 6-3 for appropriate steps.

Foam condition at the blooey line	Probable cause	Treatment
Gas blowing free with fine mist of foam	The gas has broken through the liquid foam mix, preventing the formation of stable foam.	Increase the liquid injection rate and/or decrease the gas injection rate.
Foam thin and watery (salt-cut)	Salt water from the formation is diluting the foam.	Increase the liquid and gas injection rate. If necessary, increase the percent of chemical foaming agent.
Foam thin and watery (oil-stained)	Oil from the formation is contaminating the foam.	Increase the liquid and gas injection rates.

Table 6-3: Blooey line foam conditions. Use these adjustments to correct foam based on observation at the blooey line.

Heading or regularity of foam return at the blooey line

For optimal removal of cuttings, foam returns at the blooey line should be continuous. Heading and unloading can indicate problems with the foam column.

If the hole is...	Then...
Unloading at regular intervals while drilling,	Continue drilling as long as unloading intervals are regular and short.
Heading (irregular intervals),	Increase the foam concentrate to improve foam quality.

Foam drilling formulations and applications

QUIK-FOAM, Baroid's principal agent for foam-drilling systems, is nontoxic and biodegradable. It should be used at concentrations of 3 to 4 pints per barrel for foam injection.

Stiff foams

Drilling fluid additives can be added to the foam when specific problems, such as water influx, occur. For severe water influx, the following modified QUIK-FOAM systems can be used:

- Water influx QUIK-FOAM
- KCl/QUIK-FOAM
- Di-ammonium phosphate (DAP)/QUIK-FOAM
- HEC/QUIK-FOAM

The Marsh funnel viscosity test is the only control test for the foam-injection mixture. A test result of 40 to 50 seconds/qt is standard. Check the funnel viscosity before adding QUIK-FOAM.

Water influx QUIK-FOAM. The following QUIK-FOAM formulation is for cases of severe water influx.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
Soda ash	Improves foaming ability and maximizes bentonite yield	1.0 (3)
AQUAGEL	Gives foam stability and is the primary component of the filter cake	12.0 (36)
PAC-R	Polymer additive that adds stiffness and stability to the foam and reduces the permeability of the filter cake	1.0 (3)
QUIK-FOAM	Foaming agent	0.01-2% by volume injection fluid

Table 6-4: Water influx QUIK-FOAM. For best results, this fluid should have a Marsh funnel viscosity of 40 to 50 sec/qt before QUIK-FOAM is added.

When formulating a QUIK-FOAM system:

- Add materials in the order listed.
- Add QUIK-FOAM after the initial mixing and stir gently to prevent foam formation before injection.

KCl/QUIK-FOAM. The following QUIK-FOAM formulation is for cases of severe water influx with water-sensitive shales.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
AQUAGEL (optional)	Pre-hydrated; functions same as water influx QUIK-FOAM	6.0-8.0 (17-23)
Potassium chloride (KCl)	Helps prevent caving in water-sensitive shales	10.0-25.0 (29-71)
PAC-R	Functions same as water influx QUIK FOAM	0.75-1.5 (2.1-4)
QUIK-FOAM	Foaming agent	0.01-2% by volume injection fluid
BARACOR 700	Corrosion inhibitor	1.0-2.0 (3-6)

Table 6-5: KCl/QUIK-FOAM. This mixture is especially effective for controlling water influx with water-sensitive shales exposed.

DAP/QUIK-FOAM. The following QUIK-FOAM formulation is for cases of severe water influx, corrosion and water-sensitive shale problems in environmentally sensitive areas.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
DAP (Diammonium phosphate)	For corrosion only For shale stability	2.0 (6) 6.0 (17)
PAC-R	Stiffness and hole stability	1.5-2.5 (4-7)
EZ-MUD	Additional hole stability or stiffness; can also be substituted for PAC-R	1.0-2.0 (3-6)
QUIK-FOAM	Foaming agent	0.01-2% by volume injection fluid
BARACOR 700	Corrosion inhibitor	1.0-2.0 (3-6) *Note: BARACOR 700 may not be needed in this system.*

Table 6-6: DAP/QUIK-FOAM. This foam mixture has proven useful in shale formations with severe water influx where sensitive shales are exposed and in environmentally sensitive areas.

HEC/QUIK-FOAM. The following QUIK-FOAM formulation is used where an acid soluble polymer is needed to avoid formation damage.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
BARAVIS	Viscosifier	1.5-2.5 (4-7)
Potassium chloride (optional)	Inhibits shale swelling	10.0-25.0 (29-71)
QUIK-FOAM	Foaming agent	0.01-2% by volume injection fluid
BARACOR 700	Corrosion inhibitor	1.0-2.0 (3-6)

Table 6-7: HEC/QUIK-FOAM. This foam mixture can be acidized to remove polymer from sensitive formations.

Aerated mud

Aerated mud systems reduce lost circulation in areas with very low fracture gradients. At the same time, shale hydration and corrosion are minimized. Effective mud weights of 4 to 6 pounds per gallon (0.48-0.72 sg) are possible with an aerated system. These weights substantially reduce differential pressure in the wellbore. Because of the lower pressure, the driller can reach a higher penetration rate than is possible with normal drilling fluids.

Equipment requirements

The following equipment is needed for an aerated mud system:

- An air compressor capable of 850 SCFM
- A back-up compressor capable of 850 SCFM

Note: When comparing compressor ratings, remember that ratings are made at ***sea level****. Adjust the ratings as necessary to allow for the altitude at the drilling site.*

- An air bypass (or other means of limiting the air volume) when the total compressor capacity is not required, as with a surface hole
- A Barton recorder for gauging the actual CFM of air injected
- A rotating head to direct the air and mud flow out of the flowline instead of up through the rotary table or over the drilling nipple into the cellar

Note: The rotating head should be maintained to prevent mud loss at the head. If the drilling crew is not paying close attention, an undetected loss at the

head can be mistaken for lost circulation in the hole.

- An air-mud separator (gas buster) at the flowline

  Note: The separator is typically a cylindrical tank 3 to 6 feet in diameter and 8 to 10 feet high with baffles to help break the air out of the mud.

  - An air vent on the top of the tank aimed toward the reserve pit

    Note: This vent also accommodates overflow when the return is hard
  - A mud flow discharge on the bottom of the tank for discharge into the possum belly

Lime/ IMPERMEX mud system formulation and applications

A lime/IMPERMEX mud system is used when corrosion and/or reactive formations may be a problem. The following table provides formulations for the lime/IMPERMEX mud system.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
AQUAGEL	Provides suspension and borehole stability	3.0-5.0 (9-14)
ENVIRO-THIN	Reduces gel strength	As needed
IMPERMEX	Controls the filtration rate	2.0-5.0 (6-14)
Lime	Inhibits corrosion and shale swelling	0.8-1.5 (2.3-4)
X-CIDE 207	Controls bacterial growth	As needed

Table 6-8: Lime/IMPERMEX mud system. This system is used when corrosion and/or reactive formations may be a problem.

The lime/IMPERMEX mud will have the following properties:

Mud weight	8.6-8.8 lb/gal
Funnel viscosity	28-32 sec/qt
Plastic viscosity	1-9 cP
Yield point	0-2 lb/100 ft^2
Gels	0/0 lb/100 ft^2
API filtrate	8-10 mL
pH	11.5-12.5
Calcium	240-450 mg/L
Solids	1-3 % by vol

DAP/PAC mud system formulation and applications

A DAP/PAC mud system can be used for additional inhibition and corrosion protection. The system is run at a low pH and the phosphate ion provides corrosion protection while the ammonium ion provides shale inhibition.

Additive	Function	Typical concentrations lb/bbl (kg/m^3)
AQUAGEL	Provides viscosity and wall cake	8-12 (23-34)
DAP	Provides shale stability and corrosion control	2-6 (6-17)
EZ-MUD	Provides viscosity and shale stability	0.50-1.50 (1.4-4)
PAC-R	Controls fluid loss	0.50-1.50 (1.4-4)

Table 6-9: DAP/PAC mud system. This system can be used for additional inhibition and corrosion protection.

The DAP/PAC mud will have the following properties:

Mud weight	8.6-8.9 lb/gal
Funnel viscosity	35-40 sec/qt
Plastic viscosity	1-12 cP

Yield point	6-8 lb/100 ft^2
Gels	2-5 lb/100 ft^2
API filtrate	8-10 mL
pH	7-8
Solids	1-3 % by vol

Note: Do not add caustic soda or lime because ammonia will be liberated. DAP/PAC mud is not recommended for carbon dioxide (CO_2) or hydrogen sulfide (H_2S).

Recommended operating procedures for aerated mud

When using aerated mud systems:

- Inject air into the standpipe and arrange the piping so air can be bypassed at the floor for making connections, etc.
- Plumb the piping so mud can be pumped downhole while air is bypassed.
- Run the bit with open water courses (no jets) to prevent excessive air pressure requirements. With the reduced bottomhole pressure, jet impact is not as critical for cleaning the bottom of the hole.
- Larger drillpipe sizes of 4 1/2 or 5 inches are recommended to reduce compressor volume requirements.
- Filling the hole between trips is not necessary with aerated mud.
- Circulate the mud system at a constant rate of 6 to 8 bbl per minute and treat it as a normal mud system. Do not vary pump output to maintain constant bottomhole pressure or to control gains and losses; instead, regulate the airflow to correct these problems.
- Use the aerated mud chart to determine the amount of air to inject to achieve a specific reduction in bottomhole pressure.
- Install float valves in the drillstring approximately every 200 feet (61 meters) to prevent backflow on connections.

Determining hydrostatic loss caused by gas-cut mud

To find Bottom Hole Pressure (BHP) loss due to gas-cut mud:

1. Find hydrostatic pressure of uncut mud.
2. Start with hydrostatic pressure at bottom of chart. (See Figure 6-1.)
3. Proceed up to intersect percent gas in mud.
4. Read on right the BHP loss due to gas content.
5. Subtract loss from original BHP to find new effective head of gas-cut mud.

Moderate gas cutting reduces measured mud weights on the surface, but, due to gas behavior under pressure, produces little effect on the effective hydrostatic head at depth.

When minimum overbalances are being used, or gas cutting becomes severe, an accurate method of determining the BHP reduction is needed. (See note below.) This graphical solution disregards the effect of gas density and thus provides a tool useful for either gas or air. As such, it becomes useful for determining air injection volumes required for a desired reduction of hydrostatic pressure.

Note: White, R. J. "Bottom-Hole Pressure Reduction Due to Gas Cut Mud," Journal of Petroleum Technology, July 1957.

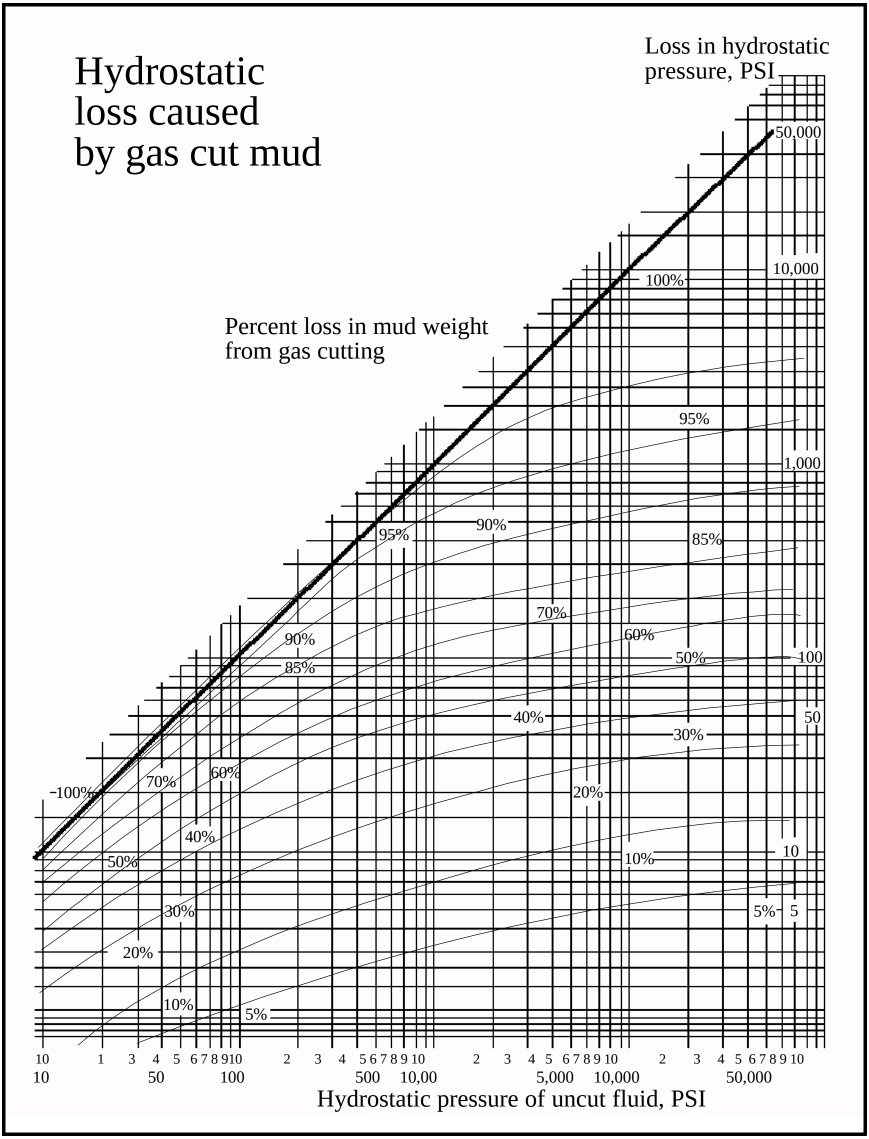

Figure 6-1: Hydrostatic loss caused by gas-cut mud. This chart is useful for determining air injection volumes required for a desired reduction of hydrostatic pressure.

Corrosion

Foam and aerated fluids can be corrosive. The injected air contains carbon dioxide and oxygen that promote corrosion. Inhibitors are needed to counter the effect of these gases. The products in the following table are recommended for corrosion problems.

Product	Application	Treatment
BARACOR 700	Inhibits corrosion by treating mud slurry	Treat mud initially at 1,500 ppm, then 0.5-1.5 lb/bbl (1.4-4 kg/m^3).
BARAFILM	Inhibits corrosion by coating pipe	1.5-2.0 gal per 1,000 ft of pipe every 1 to 4 hours.
STABILITE	Inhibits scale	Add to mud at 10-100 ppm, then 1 gal/tour to 1 gal/hr.

Table 6-10: Corrosion products. This table lists products that combat corrosion and provides recommended applications and treatments.

Examine corrosion coupons and rings to ensure that enough inhibitors are being used.

For more information on how to treat for carbon dioxide and oxygen contamination, see the chapter titled *Corrosion*.

CHAPTER 7

Lost circulation

The Complete Fluids Company

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Overview

Lost circulation or loss of returns describes the complete or partial loss of fluid to the formation as a result of excessive hydrostatic and annular pressure drop. Lost circulation is characterized by a reduction in the rate of mud returns from the well compared to the rate at which it is pumped downhole (flow out < flow in). This leads to a decrease in pit volumes. Loss of circulation may be detected by a sensor monitoring return flow rate or by pit volume indicators. Depending on the severity of the rate of mud loss, drilling operations may be significantly impaired. If the annulus of the well will not remain full even when circulation of the fluid has ceased, the hydrostatic pressure will reduce until the differential pressure between the mud column and the loss zone is zero. This may induce formation fluids from other zones, previously controlled by the mud hydrostatic pressure, to flow into the wellbore resulting in a kick, blowout, or underground blowout. It may also cause previously stable formations to collapse into the wellbore.

Lost circulation can occur in the following formations:

Type of formation ...	Type of loss ...
Cavernous/vugular	Complete or partial
Highly permeable or fractured	Complete or partial
Permeable	Seepage loss

Formations in which circulation may be lost

Cavernous/ vugular formations

The circulation lost in a cavernous/vugular formation is the most severe type of loss that can occur because the mud loss is immediate and complete. Cavernous formations are associated with limestone reefs, dolomite beds, or chalks. The loss occurs in actual caverns or crevices in the formation.

Indication

This type of lost circulation is usually easy to diagnose because the bit can drop several inches or even feet when it breaks through the top of the cavern.

Treatment

The following methods are recommended for combating lost circulation due to cavernous/vugular formations:

- Add 40 to 60 lb/bbl (114-171 kg/m^3) coarse-grade products such as:
  - — BARACARB
  - — BARO-SEAL
  - — BAROFIBRE Coarse
  - — JELFLAKE
  - — MICATEX
  - — STEELSEAL
  - — WALL-NUT
- Spot a high filtration pill such as Diaseal® M or ZEOGEL.
- Spot a gunk diesel-oil-bentonite (DOB) or diesel-oil- bentonite cement (DOBC) squeeze pill. Synthetic based fluids may be substituted as a carrier.
- Drill blind (if possible) until the loss zone can be cased off.

Fractured formations

Permeable or fractured formations can result in partial or complete loss of circulation. Formation fractures can be natural or caused by excessive drilling fluid pressure on a structurally weak formation. Once a fracture has been induced, the fracture will widen and take more mud at a lower pressure. To avoid inducing formation fractures:

- Maintain the minimum equivalent-circulating density (ECD) and mud weight.
- Avoid pressure surges.

Indication

Lost circulation of this type is indicated by a complete or partial loss of returns and a decrease in pit volume.

Treatment

If a induced fracture is suspected, the hole can be allowed to heal by pulling into the casing and waiting 6 to 12 hours. After the waiting period, stage back to bottom and check for full returns. If full returns have not been established, treat the losses as if they were cavernous/vugular losses.

Permeable formations

Permeable and porous formations include:

- Loose, noncompacted gravel beds
- Shell beds
- Reef deposits
- Depleted reservoirs

These types of formations cause seepage loss to complete loss of returns.

Indication

Seepage into permeable formations is indicated by partial to full loss of returns and a decrease in pit volume.

Treatment

The following methods are recommended for combating this type of loss:

- Reduce mud weight as much as possible.
- Treat the system with a combination of fine- to medium-grade lost-circulation products such as:
  — BARACARB
  — BAROFIBRE
  — BARO-SEAL
  — HY-SEAL
  — MICATEX
  — STEELSEAL

Corrective procedures and formulations

Gunk squeeze

When you are faced with a lost circulation problem and you are using an oil/synthetic mud, mix the gunk squeeze with water and GELTONE instead of oil/synthetic and bentonite. Formulations for water-based and oil/synthetic-based gunk slurries are listed in Tables 7-1 and 7-2.

Type	Additions per barrel of diesel	
	Bentonite, lb (kg)	Cement, lb (kg)
Diesel-oil/synthetic bentonite	400 (181)	0 (0)
Diesel-oil/synthetic bentonite cement	200 (91)	200 (91)

Table 7-1: Gunk formulation for water-based muds. This example uses a diesel-oil/synthetic bentonite or diesel-oil/synthetic bentonite cement mixture. If PETROFREE/ PETROFREE LE/XP-07 is being used, substitute appropriate base fluid for diesel oil.

Material	Mud weight		
	10.5 lb/gal (1.26 sg)	13 lb/gal (1.56 sg)	16 lb/gal (1.92 sg)
Water, bbl (m^3)	0.660	0.628	0.582
Q-BROXIN, lb (kg)	3.5 (10)	3.5 (10)	3.5 (10)
Caustic soda, lb (kg)	1.5 (4)	1.5 (4)	1.5 (4)
*GELTONE, lb (kg)	220 (627)	150 (428)	100 (285)
BAROID, lb (kg)	—	175 (499)	370 (1,055)

Table 7-2: Water-GELTONE gunk squeeze formulation. This formulation is for oil/synthetic-based muds. * Use the GELTONE recommended for the area.

To mix a gunk squeeze, follow these steps:

1. Drain and clean the mixing tank thoroughly.
2. Prepare a gunk slurry (diesel oil/synthetic bentonite cement, diesel-oil bentonite, or water-GELTONE; see Table 7-2).
3. Pump the following in this order:
   - Spacer to cover approx. 500' of drillstring
   - Squeeze to cover approx. 2 times open hole volume
   - Spacer to cover approx. 500' of drillstring

   Note: The spacer fluid should have the same base fluid as the squeeze.

4. Displace the squeeze to the bit.
5. Close blowout preventers (BOPs).
6. Pump down the drillpipe and annulus in equal volumes until the squeeze and spacer are displaced from the drillpipe.
7. Maintain equal pressure on drillpipe and casing.

Crosslinkable LCM pill

N-SQUEEZE may be used as an essentially non-damaging crosslinkable LCM pill. This pill is designed to control whole fluid losses or seepage losses. It may

be either pumped as a sweep or crosslinked and spotted across a loss zone.

If required, the pill may be weighted with calcium carbonate or barite. Cleanup can be accomplished by flow back, acidizing, or biodegradation.

Note: The highest degree of formation damage protection is provided when N-SQUEEZE is used alone or with calcium carbonate as a weighting agent.

The N-SQUEEZE pill may be mixed in freshwater, KCl or NaCl brines. It reaches its highest yield in water with a lower salinity value.

Formulations for water-based N-SQUEEZE pills are listed in Table 7-3.

	Mud weight		
Materials	**10.5 lb/gal (1.26 sg)**	**13.0 lb/gal (1.56 sg)**	**16.0 lb/gal (1.92 sg)**
Fresh water, bbl (m^3)	0.919	0.826	0.713
N-SQUEEZE, lb (kg)	10 (29)	10 (29)	10 (29)
BAROID, lb (kg)	120 (343)	257 (735)	422 (1206)
* N-SQUEEZE, lb (kg)	10 (29)	10 (29)	5 (14)

Table 7-3: N-SQUEEZE formulations. This type of squeeze can be pumped as a sweep or crosslinked and spotted across a loss zone.

* *Add second amount of N-SQUEEZE after all other products have been mixed and blended for 20-30 minutes.*

Notes:

- *N-SQUEEZE LCM pill can be pumped as a sweep or crosslinked.*
- *To crosslink add 5 gallons of N-PLEX per 10 barrels of N-SQUEEZE slurry pumped.*
- Water-based *N-SQUEEZE can also be used in oil/synthetic fluids*

- *Stable to 180°F*

Caution : Do not add N-PLEX directly to the N-SQUEEZE in the mixing tank. This could cause the slurry to set up and be to thick to pump.
The N-PLEX (crosslinker) should be added to the suction line at the time the N-SQUEEZE slurry is being pumped downhole.

High-filtration squeeze

A high-filtration squeeze requires tightly packed dehydrated solids to seal the loss zone.

Formulations for water-based and oil/synthetic based squeezes are listed in Tables 7-4 and 7-5.

	Mud weight		
Materials	**10.0 lb/gal (1.20 sg)**	**14.0 lb/gal (1.68 sg)**	**18.0 lb/gal (2.16 sg)**
Fresh water, bbl (m^3)	0.93	0.78	0.632
Lime, lb (kg)	0.5 (1.4)	0.5 (1.4)	0.5 (1.4)
ZEOGEL, lb (kg)	12 (34)	10 (29)	8 (23)
BAROID, lb (kg)	82 (234)	304 (866)	525 (1,496)
LCM, lb (kg)	20-60 (57-171)	20-60 (57-171)	20-40 (57-114)

Table 7-4: High-filtration water-based squeeze formulation. This type of squeeze plugs the loss zone to prevent additional losses.

Notes:

- *Sepiolite clay can be substituted for ZEOGEL.*
- *Other weighting agents such as BARACARB or BARODENSE can be substituted for BAROID.*

A high-filtration squeeze can also be used with oil/synthetics as the continuous phase for situations where oil/synthetics is the base fluid.

Materials	Amounts
Base fluid, bbl (m^3)	0.6
SUSPENTONE, lb (kg)	3 (9)
TRIMULSO, lb (kg)	1 (3)
LCM, lb (kg)	10-15 (29-43)
BAROID, lb (kg)	575 (1,639)

Table 7-5: High-filtration oil/synthetic based squeeze formulation. This mixture results in an oil/synthetic based squeeze weighing 18 lb/gal (2.16 sg).

Note: BARACARB can be substituted for BAROID in this formulation. The maximum pumpable density when using BARACARB is 14.0 lb/gal (1.68 sg).

High-filtration squeeze procedure:

1. Spot the slurry into the loss zone.
2. Close blowout preventers (BOPs).
3. Apply pressure for several hours.

The formulation for a Diaseal M slurry with oil is listed in Table 7-6. Because of variations in the densities of oil and barite, pilot tests should be conducted to determine exact formulations. If the slurry becomes too thick, add up to 1 lb/bbl (3 kg/m^3) EZ MUL or DRILTREAT oil-wetting agent.

Density, lb/gal (sg)	Diaseal M, lb (kg)	Barite, lb (kg)	Oil, bbl (m^3)
8.0 (0.96)	4,400 (1,996)	3,800 (1,724)	88.0 (14)
9.0 (1.08)	4,100 (1,860)	8,800 (3,992)	85.5 (13.6)
10.0 (1.20)	3,800 (1,724)	13,800 (6,260)	83.0 (13.2)
11.0 (1.32)	3,500 (1,588)	18,800 (8,528)	80.5 (12.8)
12.0 (1.44)	3,250 (1,474)	23,800 (10,796)	77.0 (12.2)
13.0 (1.56)	3,000 (1,361)	29,000 (13,154)	74.5 (11.8)
14.0 (1.68)	2,700 (1,225)	34,300 (15,558)	72.0 (11.4)
15.0 (1.80)	2,400 (1,089)	39,700 (18,008)	69.5 (11.0)
16.0 (1.92)	2,150 (975)	45,200 (20,503)	67.0 (10.6)
17.0 (2.04)	1,900 (862)	50,800 (23,043)	64.5 (10.2)
18.0 (2.16)	1,650 (748)	56,500 (25,628)	61.0 (9.7)

Table 7-6: Diaseal M oil slurry formulation. This formulation is for 100 bbl of slurry.

Note: Lost circulation materials may be added to the Diaseal M squeeze. If absorbent lost-circulation materials are added, the slurry viscosity will increase. This slurry is effective without conventional lost-circulation materials.

Locating the loss zone

The best source of information for determining loss zones is your knowledge of the formations and the characteristics of a given region.

If there …	Then the loss zone is probably at the …
Is an indication of formation change	Bit
Has been an increase in density	Weakest point in the hole (i.e., below the last casing shoe)

More specific methods for locating the loss zone include:

- Measurement-while-drilling (MWD) tools such as Sperry Sun's Formation-Evaluation-While-Drilling (FEWD)
- Radioactive tracers
- Temperature surveys
- Hot-wire surveys

CHAPTER 8

Oil-based muds

The Complete Fluids Company

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Overview

Oil-based muds are muds in which the continuous, or external, phase is an oil, such as diesel or mineral oil. The properties of oil-based muds are influenced by the following:

- Oil/water ratio
- Emulsifier type and concentration
- Solids content
- Downhole temperature and pressure

Oil-based mud systems

Oil-based mud systems are classified in four categories. Table 8-1 outlines the primary uses of these different systems.

System	Application
Tight-emulsion	For general use as well as high-temperature areas up to 500°F (260°C)
Relaxed-filtrate (RF)	To provide increased drilling rates
All-oil	For use as nondamaging coring and drilling fluid For use as a high temperature oil-based mud
High water	To minimize oil retention on cuttings; used primarily in offshore areas that are environmentally sensitive

Table 8-1: Oil-based mud systems. Each oil-based mud system was developed to meet specific drilling requirements.

Either diesel oil or mineral oil is used as the base fluid for oil-based muds. Table 8-2 outlines the system names by base oil.

System	Base oil—Diesel	Base oil—Mineral
Tight-emulsion	INVERMUL	ENVIROMUL
Relaxed-filtrate (RF)	INVERMUL RF	ENVIROMUL RF
All-oil	BAROID 100	ENVIROMUL 100
High water	INVERMUL 50/50	ENVIROMUL 50/50

Table 8-2: System names by base oil. The product to use for a given system depends on the base oil.

Tight-emulsion systems

INVERMUL and ENVIROMUL tight-emulsion systems provide high-temperature stability and tolerance to contaminants. These systems use high concentrations of emulsifiers and fluid-loss agents for maximum emulsion stability and minimal filtrate loss. The volume of the HTHP filtrate is usually less than 15 mL and should be all oil. Table 8-3 provides guidelines for formulating tight-emulsion systems.

Additive	Function	Concentrations, lb/bbl (kg/m^3)	
		To 300°F (149°C)	To 400°F (205°C)
Oil	Continuous phase	As needed	As needed
INVERMUL INVERMUL NT	Primary emulsifier	6-8 (17-23)	8-16 (23-46)
Lime	Alkalinity source	3-4 (9-11)	4-8 (11-23)
DURATONE HT	Fluid loss control agent	6-8 (17-23)	8-20 (23-57)
Water	Discontinuous phase	As needed	As needed
GELTONE II/V	Viscosifier	0.5-3 (1.4-9)	2-8 (6-23)
EZ MUL EZ MUL NT	Secondary emulsifier	1-2 (3-6)	2-8 (6-23)
BAROID BARODENSE or BARACARB	Weighting agent	As needed	As needed
$CaCl_2$	Salinity source	As needed	As needed

Table 8-3: Tight-emulsion system formulation guidelines. The base fluid of an INVERMUL system is diesel; the base fluid of an ENVIROMUL system is mineral oil.

Relaxed-filtrate (RF) systems

INVERMUL RF and ENVIROMUL RF relaxed-filtrate systems have no or very low concentrations of INVERMUL emulsifier and DURATONE HT filtration control agent. The increased filtrate in these systems promotes faster drilling rates than are possible with tight-emulsion systems. The volume of the HTHP fluid loss is 15 to 20 cm^3 with optimized spurt loss. These systems are stable at temperatures up to 325°F (163°C). Table 8-4 provides guidelines for formulating RF systems.

Additive	Function	Concentrations, lb/bbl (kg/m^3) to 300°F (149°C)
Oil	Continuous phase	As needed
EZ MUL EZ MUL NT	Emulsifier	2-4 (6-11)
Lime	Alkalinity source	2-6 (6-17)
DURATONE HT	Filtration control agent	0-3 (0-9)
Water	Discontinuous phase	As needed
GELTONE II/V	Viscosifier	2-8 (6-23)
INVERMUL INVERMUL NT	Emulsifier	0-2 (0-6)
BAROID BARODENSE or BARACARB	Weighting agent	As needed
$CaCl_2$	Salinity source	As needed

Table 8-4: RF system formulation guidelines. The base fluid of an INVERMUL RF is diesel; the base fluid of an ENVIROMUL RF system is mineral oil.

All-oil drilling/coring BAROID 100

BAROID 100, an all-oil system, is used when maintaining the native state of the geologic formation is a primary concern. This system is not used where water contamination is a known problem. Table 8-5 provides guidelines for formulating a BAROID 100 system.

Additive	Function	Concentrations, lb/bbl (kg/m^3) to 350°F (177°C)
Oil	Continuous phase	As needed
Lime	Alkalinity source	1-3 (3-9)
EZ-CORE	Passive emulsifier	2.0 (6)
*EZ MUL *EZ MUL NT	Emulsifier	2-4 (6-11)
BARABLOK or BARABLOK 400 or DURATONE HT	Filtration control agent	5-15 (14-43)
AK-70	Filtration control agent	15-25 (43-71)
GELTONE II/V	Viscosifier	6-14 (17-40)
BARACTIVE	Polar additive	2-6 (6-17)
BAROID BARODENSE or BARACARB	Weighting agent	As needed

Table 8-5: BAROID 100 formulation guidelines. The base fluid of a BAROID 100 system can be diesel or mineral oil.

* EZ MUL, EZ MUL NT may be added when a large amount of water contamination occurs.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

All-oil drilling BAROID 100 HT

BAROID 100 HT, an all-oil system, is used when bottom hole circulation and bottom hole temperatures are anticipated in the 350 to 425°F (177 - 218°C) range. BAROID 100 HT tolerates water contamination at high temperatures with minimal effect on properties. BAROID 100 HT utilizes both a primary and secondary emulsifier which gives the system greater tolerance to water contamination and the capacity to achieve high mud weights. Table 8-6 provides guidelines for formulating a BAROID 100 HT system.

Additive	Function	Concentrations, lb/bbl (kg/m^3) to 425°F (218°C)
Oil	Continuous phase	As needed
Lime	Alkalinity source	6-10 (17-28)
THERMO MUL	Emulsifier	6-10 (17-28)
THERMO PLUS	Passive Emulsifier	2-5 (6-14)
BARABLOK 400 or DURATONE HT or XP-10	Filtration control agent	5-15 (14-43)
GELTONEV	Viscosifier	6-14 (17-40)
BARACTIVE	Polar additive	2-6 (6-17)
BAROID BARODENSE	Weighting agent	As needed
X-VIS	Viscosifier	1-3 (3-9)

Table 8-6: BAROID 100 HT formulation guidelines. The base fluid of a BAROID 100 HT system be diesel, mineral oil or XP-07.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

High-water systems

INVERMUL 50/50 and ENVIROMUL 50/50 high-water systems were developed for use in areas where discharges of oil are restricted, such as in the North Sea. These systems, which have a 50/50 oil-to-water ratio, can reduce the oil left on cuttings by as much as 45 percent. High-water systems are not recommended at temperatures greater than 250°F (121°C). Table 8-7 provides guidelines for formulating high-water systems.

Additive	Function	Concentrations, lb/bbl (kg/m^3) to 250°F (121°C)
Oil	Continuous phase	As needed
INVERMUL INVERMUL NT	Primary emulsifier	1-2 (3-6)
DURATONE HT	Filtration control agent	4-8 (11-23)
Lime	Alkalinity source	2-6 (6-17)
Water	Discontinuous phase	As needed
GELTONE II/V	Viscosifier	1-2 (3-6)
EZ MUL EZ MUL NT	Secondary emulsifier	4-8 (11-23)
BAROID BARODENSE or BARACARB	Weighting agent	As needed
$CaCl_2$	Salinity source	As needed

Table 8-7: High-water system formulation guidelines. The base fluid of a high-water system can be diesel or mineral oil.

Mud management

When maintaining an oil-based mud system, observe the following guidelines.

- Maintain electrical stability above 400 volts.
- Maintain an all-oil HTHP filtrate.
- Do not add weighting agents when adding water.
- Maintain excess lime at 1.5 to 3.0 lb/bbl (4.0 to 9.0 kg/m^3).
- Use solids-control equipment to prevent buildup of low-specific gravity solids.
- Add a minimum of 0.5 lb (0.5 kg) of lime for each 1 lb (1 kg) of INVERMUL or INVERMUL NT.
- Add EZ MUL or EZ MUL NT slowly as weighting agents are added to help oil-wet the additional solids.
- Do not saturate the water phase with $CaCl_2$ because emulsion instability and water wetting of solids may occur.

Logging

Oil muds do not conduct electric current; therefore, do not use logging tools that require electric conductance to measure resistivity (i.e., short-normal resistivity). Table 8-8 provides guidelines for logging in oil muds.

Objective	Tool	Notes
Depth control correlation and lithology	Induction/gamma ray log Formation density log Sonic log Neutron log Dipmeter	Use the gamma ray log to determine sand and shale sequences. Use the other logs for identifying complex lithology.
Percent shale in shaley sands	Gamma ray log	The gamma ray log method replaces the sand/shale index found in fresh waters from the SP log.
Net sand (sand count)	Formation density log Gamma ray log	Use the formation density log and/or the caliper log to determine sand count when the sand and shale densities differ.
Detect hydrocarbon-bearing formations	Induction/gamma ray log Sonic log Neutron log	High resistivity values indicate hydrocarbon pore saturation. Use a formation density log in conjunction with neutron and sonic logs to identify hydrocarbons.
Interpretation • Water saturation • Porosity • Permeability • Structural formation • Productivity	Induction, sonic, density, and neutron logs Formation density, sonic, and neutron logs; sidewall cores Sidewall cores Continuous dipmeter Formation tester	Use Archie's equation to compute water saturation.

Table 8-8: Logging and formation evaluation guidelines. A variety of tools are available to help determine downhole conditions.

Special applications

Because oil-based systems are noncorrosive, they are useful for a variety of field applications, including:

- Packer fluids and casing packs
- Arctic casing packs
- PIPE GUARD gelled-oil systems

Packer fluids and casing packs

A packer fluid could be an INVERMUL or ENVIROMUL mud that provides long-term protection from corrosion. Casing packs protect the casing from external corrosion and facilitate casing recovery. Packer fluids are used inside the casing; casing packs are placed in the annular space between the casing and the hole. Viscosify the oil-based mud to packer-fluid specifications before setting. Table 8-9 lists recommended properties of packer fluids and casing packs.

Properties	Density, lb/gal (sg)			
	12.0 (1.44)	14.0 (1.68)	16.0 (1.92)	18.0 (2.16)
Plastic viscosity, cP	60-80	60-80	70-90	80-100
Yield point, lb/100 ft^2	50-70	50-70	60-80	70-90
10-second gel, lb/100 ft^2	30-50	30-50	40-60	40-60
10-minute gel, lb/100 ft^2	40-60	40-60	40-60	50-70
Alkalinity, mL N/10 H_2SO_4/mL of mud	3-6	3-6	3-6	3-6
Electrical stability, volts, minimum	600	800	1,000	1,000
Water content, vol%	25-35	20-30	15-25	10-15

Table 8-9: Packer-fluid and casing-pack recommendations as tested at 100° F (38 ° C). Properties depend on mud weight.

Arctic casing packs

Arctic casing packs formulated from oil-based muds retard heat loss and prevent permafrost melting. Arctic casing packs also allow casing to expand and contract with temperature changes. An arctic casing pack may be prepared fresh or from an existing mud. Table 8-10 provides guidelines for formulating arctic casing packs.

Additives	Density, lb/gal (sg)		
	10.0 (1.2)	**15.0 (1.8)**	**20.0 (2.4)**
Arctic diesel oil, bbl	0.754	0.601	0.444
EZ MUL EZ MUL NT, lb	12.5	12.5	12.5
Water, bbl	0.042	0.034	0.025
GELTONE II/V lb	50	36	25
NaCl, lb	3.0	1.5	1.5
BAROID, lb	21	393	663

Table 8-10: Arctic casing pack formulation guidelines. The amount of each additive varies with the needed density of the arctic casing pack.

Preparing fresh arctic casing packs

To prepare a fresh arctic casing pack:

1. Prepare a premix at 70°F (21°C) or higher according to the formulation in Table 8-10.
2. Add half the required amount of GELTONE II/V.
3. Cool the premix to about 40°F (4.5°C).
4. Add the rest of the GELTONE II/V.
5. Pump the pack into position.

Preparing arctic casing packs from existing mud

To prepare an arctic casing pack from existing mud:

1. Adjust the water content to about 7 percent by volume and the temperature to about 70°F (21°C).
2. Conduct a pilot test to determine the needed concentration of GELTONE II/V.
3. Cool the mud to about 40°F (4.5°C).
4. Add the required GELTONE II/V.
5. Pump the pack into position.

PIPE GUARD gelled-oil systems

PIPE GUARD is designed to prevent corrosion of pipelines that pass under roadbeds and waterways. This system is available in two densities: 9.1 lb/gal (1.09 sg) for under waterways and 19.0 lb/gal (2.28 sg) for under roadbeds. Table 8-11 provides guidelines for formulating PIPE GUARD gelled-oil systems.

Additives	Density, lb/gal (sg)	
	9.1 (1.09)	**19.0 (2.28)**
Diesel oil, bbl	0.42	0.26
EZ MUL EZ MUL NT, lb	8	8
Lime, lb	5	5
Water, bbl	0.45	0.29
GELTONE II/V lb	8	8
BARACARB, lb	80	—
BAROID, lb	—	598

Table 8-11: PIPE GUARD gelled-oil system formulation guidelines. The 9.1 lb/gal (1.09 sg) system is used under waterways; the 19 lb/gal (2.28 sg) system is used under roadbeds.

Note: Mineral oil may be used in place of diesel oil, however the concentration of GELTONE II/V may need to be increased.

PIPE GUARD is usually mixed at the plant, but it can also be mixed onsite. Enough PIPE GUARD should be mixed at one time for a number of crossings. After PIPE GUARD has been loaded onto a tank truck, follow these steps at each crossing:

1. Connect the pump from the tank truck to one of the vents.

2. Connect a hose to the outlet vent on the other side of the crossing and run the hose to a small tank for waste collection.
3. Pump PIPE GUARD slowly and steadily into the conduit until clean PIPE GUARD is observed at the outlet vent.
4. Remove the connections and proceed to the next crossing.

Product information

This section provides information on viscosifiers, thinners, emulsifiers, and filtration control agents.

Viscosifiers/ suspending agents

Use organophilic clays to increase the rheological properties of oil muds. Use oil-dispersable polymeric fatty acids to enhance the low shear-rate viscosities of oil muds. Viscosifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
BARAPAK	Prevents top oil separation (packer fluids only)	Oil-soluble polymer	0-1.5 (0-4)
GELTONE II/V	Develops viscosity and suspension properties; requires a polar additive (like water) to develop maximum yield; maximum yield achieved with minimal shear	Organophilic clay	1-12 (3-34)
RM-63	Enhances low-shear rheology and gel strengths; provides gelling characteristics	Polymeric fatty acid	0.5-1.5 (1.4-4)
SUSPENTONE	Provides suspension with minimal viscosity	Organophilic clay	1-6 (3-17)
X-VIS	Improves rheological and filtration properties in high-temperature formulations; enhances low-shear rheology and gel strengths	Polymeric fatty acid	0.5-3.0 (1.4-9)

Table 8-12: Viscosifying products. A variety of products are available to increase rheological properties or enhance low shear-rate viscosities of oil-based muds.

Thinners

To thin oil-based muds, add base oil to the mud or treat the mud with a variety of oil-soluble petroleum sulfonates or polymeric fatty acid derivatives. Thinning products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
OMC	Reduces viscosity	Sulfonated petroleum derivative	0.25-1.5 (0.7-4)
OMC 42	Reduces viscosity	Polycarboxylic acid derivative	0.25-4 (0.7-11)

Table 8-13: Thinning products. Thinning products are used to make oil-based muds less viscous.

Emulsifiers

Use emulsifiers to increase the stability of the emulsion of the mud system and reduce the water-wetting tendency of the insoluble solids. Emulsifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
EZ-CORE	Passive emulsifier in the all-oil systems	Refined tall oil fatty acid	1-4 (3-11)
EZ MUL EZ MUL NT	Emulsifier in the relaxed-filtrate (RF) system	Partial amide of a fatty acid in a nontoxic solvent	1-10 (3-29)
INVERMUL INVERMUL NT	Emulsifier in the INVERMUL and ENVIROMUL systems	Blend of oxidized tall oil and polyaminated fatty acid	1-15 (3-43)
THERMO MUL THERMO PLUS	Emulsifier in the BAROID 100 HT system	Blend of oxidized tall oil and polyaminated fatty acid	1-15 (3-43)
DRILTREAT	Reduces water wetting of solids; reduces the viscosity of oil muds when large quantities of solids have been incorporated	Lecithin liquid dispersion	0.25-1.5 (0.7-4)

Table 8-14: Emulsifying products. Emulsifiers increase emulsion stability and reduce the tendency of insoluble solids to water-wet.

Filtration control agents

To provide filtration control, add organophilic lignite or various asphaltic materials. Filtration control products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
DURATONE HT	Controls fluid loss at elevated temperatures; provides high-temperature stability (400°F [204°C]) *Note: When used with all-oil systems, BARACTIVE polar activator is required to activate DURATONE HT.*	Organophilic leonardite	1-25 (3-71)
AK-70	Controls fluid loss at temperatures up to 275°F (135°C)	Blend of air-blown asphalt and clay with anti-caking agent	1-25 (3-71)
BARABLOK	Controls fluid loss at temperatures up to 350°F (177°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)
BARABLOK 400	Controls fluid loss at temperatures to 400°F (204°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)
XP-10	Controls fluid loss at temperatures to 500°F (260°C)	Polymeric filtration control agent	1-15 (3-43)

Table 8-15: Filtration control products. These products provide filtration control in oil-based muds.

CHAPTER 9

Rheology and hydraulics

The Complete Fluids Company

Contents

Overview

Fluid rheology and hydraulics are engineering terms that describe the behavior of fluids in motion.

This chapter explains rheological terms and identifies flow regimes. In addition, this chapter compares the different rheological models and discusses the conditions under which they are used. Finally, this chapter explains fluid hydraulics and provides calculations for laminar and turbulent flow.

Rheological terms

The terms and definitions in the following table are relevant to the discussion of rheology and hydraulics.

Rheological term	Symbol	Unit(s)	Definition
Shear rate	γ	sec^{-1}	The change in fluid velocity divided by the gap or width of the channel through which the fluid is moving in laminar flow.
Shear stress	τ	$lb/100\ ft^2$ Pa	The force per unit area required to move a fluid at a given shear rate; shear stress is measured on oil field viscometers by the deflection of the meter's dial at a given shear speed. The specific dial reading is usually denoted by θ. *Example: θ300 describes the dial deflection at 300 rpm on the rotational viscometer.*
Shear speed		rpm	The rotational speed on a standard oil field viscometer on which the shear stress is measured.
Viscosity	μ	centipoise cP Pa·sec	A fluid's shear stress divided by the corresponding shear rate, or $\mu = \tau/\gamma$. Fluid viscosity can be measured at a certain point or over a wide range of shear stress/shear rate measurements.

Rheological term	Symbol	Unit(s)	Definition
Effective viscosity	μ_e	cP Pa·sec	The viscosity used to describe fluid flowing through a particular geometry; as hole geometries change, so does μ_e.
Yield point	YP τ_y	lb/100 ft^2 Pa	The force required to initiate flow; the calculated value of the fluid's shear stress when the rheogram is extrapolated to the y-axis at $\gamma = 0$ sec^{-1}. *Note: The YP is a time-independent measurement and is usually associated with the Bingham model.*
Yield stress	τ_0	lb/100 ft^2 Pa	The force required to initiate flow; the calculated value of the fluid's shear stress when the rheogram is extrapolated to the y-axis at $\gamma = 0$ sec^{-1}. *Note: Yield stress is a time-independent measurement and is usually denoted in the Herschel-Bulkley (yield-power law [YPL]) model as τ_0 and Bingham model as YP. It can also be considered a gel strength at zero time.*
Gel strengths	none	lb/100 ft^2 Pa	Time-dependent measurements of a fluid's shear stress under static conditions. Gel strengths are commonly measured after 10-second, 10-minute, and 30-minute intervals, but they can be measured for any desired length of time.
Plastic viscosity	PV	cP Pa·sec	The contribution to fluid viscosity of a fluid under dynamic flow conditions. Generally the plastic viscosity is related to the size, shape, and number of particles in a moving fluid. PV is calculated using shear stresses measured at θ600 and θ300 on the FANN 35 viscometer.
Flow index	n	none	The numerical relation between a fluid's shear stress and shear rate on a log/log plot. This value describes a fluid's degree of shear-thinning behavior.
Consistency index	K	(eq) cP Pa·sec^n lb/100 ft^{2}sec^n	The viscosity of a flowing fluid identical in concept to the PV. *Note: Viscous effects attributed to a fluid's yield stress are not part of the consistency index as this parameter describes dynamic flow only.*

Table 9-1: Rheological terms. These terms are useful for understanding rheological formulas and calculations.

Flow regimes

There are three basic types of flow regimes. These are:

- Laminar
- Turbulent
- Transitional

Laminar flow occurs at low-to-moderate shear rates when layers of fluid move past each other in an orderly fashion. This motion is parallel to the walls of the channel through which the fluid is moving. Friction between the fluid and the channel walls is lowest for this type of flow. Mud rheological parameters are important in calculating frictional pressure losses for muds in laminar flow.

Turbulent flow occurs at high shear rates where the fluid moves in a chaotic fashion. Particles in turbulent flow are carried by random loops and current eddies. Friction between the fluid and the channel walls is highest for this type of flow. Mud rheological parameters are not significant in calculating frictional pressure losses for muds in turbulent flow.

Transitional flow occurs when the flow shifts from laminar flow to turbulent flow or vice versa. The critical velocity of a fluid is the particular velocity at which the flow changes from laminar to turbulent or vice versa.

Fluid types

There are two basic types of fluids, Newtonian and non-Newtonian. Rheological and hydraulic models have

been developed to characterize the flow behavior of these two types of fluids.

Newtonian fluids have a constant viscosity at a given temperature and pressure condition. Common Newtonian fluids include:

- Diesel
- Water
- Glycerin
- Clear brines

Non-Newtonian fluids have viscosities that depend on measured shear rates for a given temperature and pressure condition. Examples of non-Newtonian fluids include:

- Most drilling fluids
- Cement

Rheological models

Rheological models help predict fluid behavior across a wide range of shear rates. Most drilling fluids are non-Newtonian, pseudoplastic fluids. The most important rheological models that pertain to them are the:

- Bingham model
- Power law model
- Herschel-Bulkley (yield-power law [YPL]) model

Figure 9-1 depicts typical rheological profiles for Bingham-plastic fluids, power law fluids, and Newtonian fluids. A typical drilling fluid's rheological profile is also included to show that these rheological models do not characterize non-Newtonian drilling fluids very well. The Herschel-Bulkley (yield-power law [YPL]) model is the most accurate model for

predicting the rheological behavior of common drilling fluids.

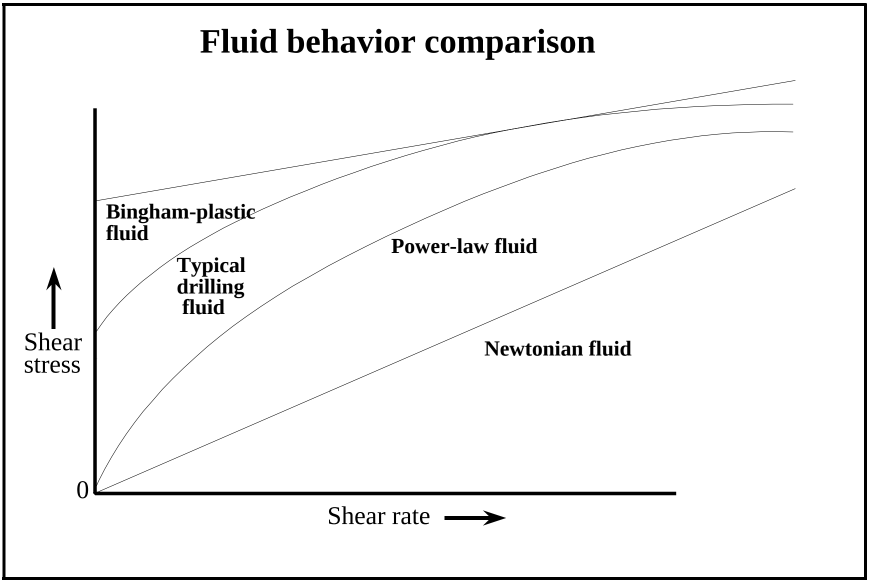

Figure 9-1: Fluid behavior comparison. This chart shows that the Bingham, power law, and Newtonian fluid models do not predict the same behavior as a typical drilling fluid.

Bingham model

The Bingham model describes laminar flow using the following equation:

$\tau = YP + (PV \times \gamma)$

Where

τ is the measured shear stress in lb/100 ft^2
YP is the yield point in lb/100 ft^2
PV is the plastic viscosity in cP
γ is the shear rate in sec^{-1}

Current API guidelines require the calculation of YP and PV using the following equations:

PV = $\theta 600 - \theta 300$

YP = $\theta 300$ – PV, or

YP = $(2 \times \theta 300) - \theta 600$

Because the model assumes true plastic behavior, the flow index of a fluid fitting this model must have n = 1. Unfortunately, this does not often occur and the model usually overpredicts yield stresses (shear stresses at zero shear rate) by 40 to 90 percent. A quick and easy method to calculate more realistic yield stresses is to assume the fluid exhibits true plastic behavior in the low shear-rate range only. A low shear-rate yield point (LSR YP) can be calculated using the following equation:

LSR YP = $(2 \times \theta 3) - \theta 6$

This calculation produces a yield-stress value close to that produced by other, more complex models and can be used when the required computer algorithm is not available.

Power law model

The power law model describes fluid rheological behavior using the following equation:

$\tau = K \times \gamma^n$

This model describes the rheological behavior of polymer-based drilling fluids that do not exhibit yield stress (i.e., viscosified clear brines). Some fluids viscosified with biopolymers can also be described by power-law behavior.

The general equations for calculating a fluid's flow index and consistency index are:

$$n = \frac{\log(\tau_2/\tau_1)}{\log(\gamma_2/\gamma_1)}$$

$$K = \frac{\tau_2}{\gamma_2^{\,n}}$$

Where

τ is the calculated shear stress in lb/100 ft^2
τ_2 is the shear stress at higher shear rate
τ_1 is the shear stress at lower shear rate
n is the flow index
γ is the shear rate in sec^{-1}
γ_2 is the higher shear rate
γ_1 is the lower shear rate
K is the consistency index

Example

Using the shear stresses measured at shear rates equal to θ600 and θ300, the general equations become:

$$n = \frac{\log\left[\frac{\theta 600}{\theta 300}\right]}{\log\left[\frac{600}{300}\right]}$$

or

$$n = 3.32 \times \log\left[\frac{\theta 600}{\theta 300}\right]$$

$$K = \frac{511 \times \theta 300}{511^n} \text{ (in eq cP) or}$$

$$K = \frac{511 \times \theta 600}{1022^n} \text{ (in eq cP)}$$

Note: The power law model can produce widely differing values of n and K. The results depend on the shear-stress/shear-rate data pairs used in the calculations.

Herschel-Bulkley (yield-power law [YPL]) model

Because most drilling fluids exhibit yield stress, the Herschel-Bulkley (yield-power law [YPL]) model describes the rheological behavior of drilling muds more accurately than any other model. The YPL model uses the following equation to describe fluid behavior:

$$\tau = \tau_0 + (K \times \gamma^n)$$

Where

τ is the measured shear stress in lb/100 ft^2
τ_0 is the fluid's yield stress (shear stress at zero shear rate) in lb/100 ft^2
K is the fluid's consistency index in cP or lb/100 ft^2 sec^n
n is the fluid's flow index
γ is the shear rate in sec^{-1}

K and n values in the YPL model are calculated differently than their counterparts in the power law model. The YPL model reduces to the Bingham model when n = 1 and it reduces to the power law model when $\tau_0 = 0$. An obvious advantage the YPL model has over the power law model is that, from a set of data input, only one value for n and K are calculated.

Note: The YPL model requires:

- *A computer algorithm to obtain solutions.*
- *A minimum of three shear-stress/shear-rate measurements for solution. Model accuracy is improved with additional data input.*

- $$\text{lb/100 ft}^2\,\text{sec}^n = \frac{\text{eq cP}}{478.8}$$

Fluid hydraulics calculation terms

Mathematical equations are used to predict the behavior of drilling fluids flowing through pipes and annulars. Fluid velocities and pressure drops encountered while circulating are of particular importance to drilling operations. Several important terms used in hydraulics calculations are defined below.

Reynolds number (N_{Re})

A dimensionless, numerical term governs whether a flowing fluid will be in laminar or turbulent flow. Often, a Reynolds number greater than 2,100 will mark the onset of turbulent flow, but this is not always so.

Critical Reynolds number (N_{Rec})

This value corresponds to the Reynolds number at which laminar flow turns to turbulent flow.

Friction factor (f)

This dimensionless term is defined for power law fluids in turbulent flow and relates the fluid Reynolds number to a "roughness" factor for the pipe. Figure 9-2 shows the relationship between Reynolds number and friction factor for laminar flow (N_{re} < 2,100), and for several values of n for fluids in turbulent flow (Re > 2,100).

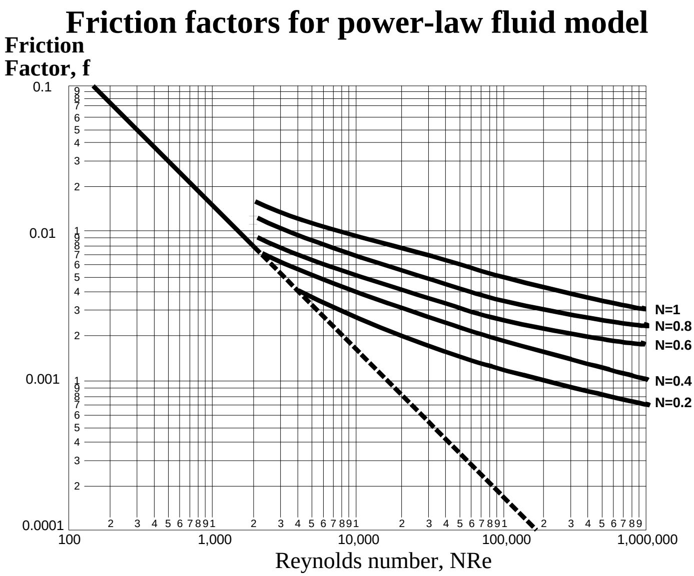

Figure 9-2: Friction factors for power law fluids. This graph shows friction factors versus Reynolds numbers for power law fluids having different values of n.

Hedstrom number (N_{He})

This dimensionless term predicts the onset of turbulent flow for fluids that follow the Bingham model. It is correlated with the critical Reynolds number (N_{Rec}), as shown in Figure 9-3.

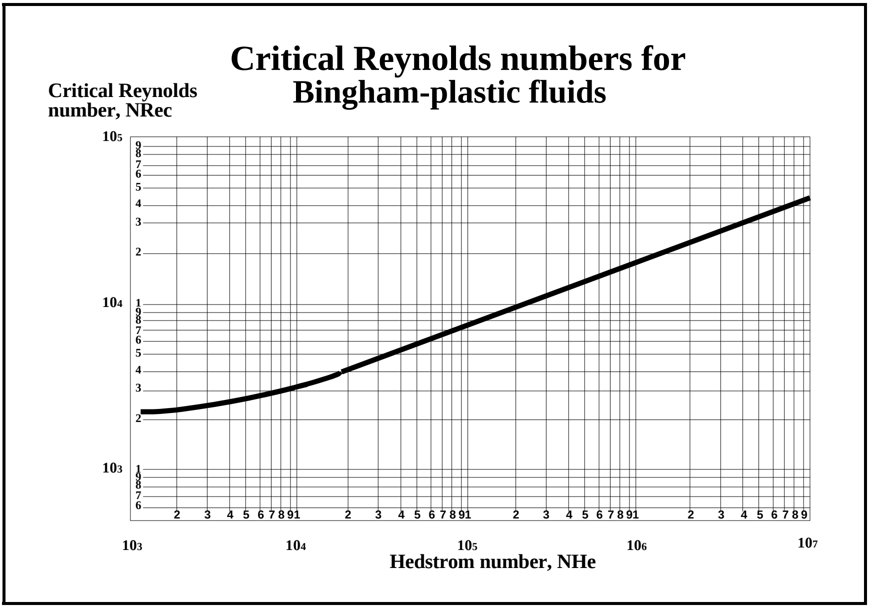

Figure 9-3: Critical Reynolds numbers for Bingham-plastic fluids. This graph shows Hedstrom numbers versus Reynolds numbers for Bingham-plastic fluids.

Effective viscosity (μ_e)

This term describes the viscosity of the fluid flowing through a particular geometry. It is different from the viscosity determined from the viscometer because the geometries or wall gaps have changed. Similarly, the fluid flowing inside the drillpipe and in the annulus will have different effective viscosities. Power law fluids will then have different flow indexes (n_p and n_a) and different consistency indexes (K_p and K_a) as compared to the n and K values calculated from viscometer θ600 and θ300.

Pressure drop (ΔP/ΔL)

Frictional forces develop when fluids flow through a pipe or an annulus. As a result, fluid energy dissipates. These frictional forces are referred to as pressure drops, and are usually referred to as a pressure per unit length. The longer a pipe or annulus, the greater the pressure drop. Factors that can affect the magnitude of pressure drop include:

- Length
- Flow rate (flow regime type laminar or turbulent)
- Fluid rheological properties
- Pipe eccentricity
- Pipe/annulus geometry
- Pipe roughness, etc.

Eccentricity (ϵ)

This dimensionless term refers to the position of a pipe inside another pipe. In the oil field it usually refers to the position of the drillpipe in an annulus. When the drillpipe lies directly in the middle of the annulus, the drillpipe's position is concentric and the eccentricity factor is 0. See Figure 9-4 (a).

As the drillpipe moves to one side of the annulus, the drillpipe becomes increasingly eccentric. If the sides of the drillpipe come in contact with the wall of the annulus, the drillpipe is fully eccentric and the eccentricity factor is 1.0. See Figure 9-4 (b).

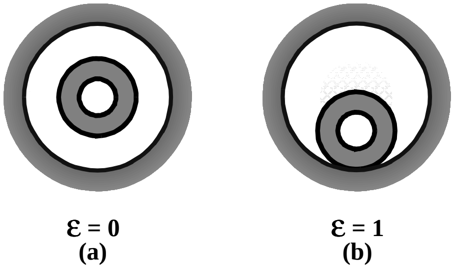

Figure 9-4: Eccentricities of a pipe in an annulus. As the drillpipe moves to one side of the annulus, the drillpipe becomes increasingly eccentric.

In high-angle or horizontal wells, the drillpipe usually lies on the low side of the hole and its eccentricity factor is 1 >= ϵ >= 0. If the drillpipe lies on the upper side of the hole, its eccentricity factor is negative 0 >= ϵ >= -1. Drillpipe eccentricity can affect pressure drops in the annulus by reducing the frictional forces of fluid flow. A fully concentric drillpipe in an annulus has the highest pressure drops.

Fluid hydraulics equations

Fluid hydraulic equations have been constructed using rheological parameters from the Bingham and power law models. Typically, pressure drop calculations for laminar flow situations made using the Bingham model

parameters overpredict actual pressure drops while those made using the power law model parameters underpredict actual pressure drops. Errors in pressure drop calculations can produce further errors in other calculations, such as equivalent circulating density (ECD).

Hydraulic equations have been written using the YPL model and their solutions can be calculated using the computer programs. Because the YPL model better predicts drilling fluid rheological behavior at low shear rates, more accurate values result for pressure drops in laminar flow, ECDs, etc.

Pump and circulating information

Pump output per stroke

Duplex pump (bbl/stroke):

$$\text{Pump output} = \frac{\text{efficiency}}{100} \times \frac{(2\ \text{liner}^2 - \text{rod diameter}^2) \times \text{stroke}}{6176.4}$$

Triplex pump (bbl/stroke):

$$\text{Pump output} = \frac{\text{efficiency}}{100} \times \frac{\text{liner}^2 \times \text{stroke}}{4117.6}$$

Where

- *Efficiency* is the percent of volumetric efficiency
- *Liner* is the pump liner diameter in inches
- *Stroke* is the pump stroke length in inches

Pump output

$$\text{Pump output, bbl/min } (PO_{BPM}) = \text{pump output (bbl/stroke)} \times \text{strokes per minute}$$

$$\text{Pump output, gal/min } (PO_{GPM}) = PO_{BPM} \times 42$$

Annular velocity

Annular velocity (V_a), ft/min:

$$V_a = \frac{1029.4 \times PO_{BPM}}{ID_{HOLE}^2 - OD_{DP}^2}$$

Where

- PO_{BPM} is the pump output in barrels per minute
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is drillpipe outside diameter in inches

Volumes

Drillpipe or drill collar capacity

$$C_I = ID_{DP}^2 \times 0.00097144 \times L_i$$

Where

- C_I is the interval capacity of the drillpipe or drill collars in barrels
- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- L_1 is the length of the interval in feet

Drillpipe or drill collar interval displacement

$$D_I = (OD_{DP}^2 - ID_{DP}^2) \times 0.00097144 \times L_i$$

Where

- D_I is the interval displacement of the drillpipe or drill collars in barrels
- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches
- L_i is the length of the interval in feet

Annular Volume

$$V_{Ann_I} = (ID_{HOLE}^2 \times 0.00097144 \times L_i) - C_I - D_I$$

Where

- C_I is the interval capacity of the drillpipe or drill collars in barrels
- D_I is the interval displacement of the drillpipe or drill collars in barrels
- V_{Ann_I} is the annular volume of the interval in barrels
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- L_i is the length of the interval in feet

$$V_{hole_I} = V_{Ann_I} + C_I$$

- Fluid volume in the hole is the sum of the annular volume and the volume of fluid inside the drillpipe

Circulating times

$$BU\ (min) = \frac{V_{Ann_{Total}}}{PO_{BPM}}$$

Where

- BU is the bottom up time in minutes
- PO_{BPM} is the pump output in barrels per minute
- $V_{Ann_{Total}}$ is the total annular volume in barrels

$$TCT\ (min) = \frac{V_{Ann_{Total}} + C_T + V_{Pits}}{PO_{BPM}}$$

Where

- TCT is the total circulating time in minutes
- PO_{BPM} is the pump output in bll/min
- $V_{Ann_{Total}}$ is the total annular volume in barrels
- C_T is the total capacity of the drillpipe and drill collars in barrels
- V_{Pits} is the total circulated pit volume in barrels

Bit hydraulics

Nozzle area

$$A_N\ (in^2) = \sum_{i=1}^{n} (Jet_i^{\,2}) \times 0.000767$$

Nozzle velocity

$$V_N\ (ft/sec) = \frac{PO_{GPM} \times 0.32}{A_N}$$

Bit pressure drop

$$PD_{Bit}\ (psi) = \frac{V_N^{\,2} \times \rho}{1120}$$

Bit hydraulic horsepower

$$HHP_{Bit}\ (hp) = \frac{PD_{Bit} \times PO_{GPM}}{1714}$$

Bit hydraulic horsepower per unit bit area

$$HHP/area = \frac{HHP_{Bit}}{A_{Bit}}$$

Percent pressure drop at bit

$$\frac{PD_{Bit}}{Press_{Pump}} \times 100$$

Jet impact force

$$Imp_{Bit}\ (lbf) = \frac{V_N \times PO_{GPM} \times \rho_{mud}}{1932}$$

Where

- ρ_{mud} is the mud density in lb/gal
- $Press_{Pump}$ is the pump pressure in psig
- PO_{GPM} is the pump output in gal/min
- Jet_i is the nozzle diameter in 32nds of an inch
- A_{Bit} is the area of the bit

- A_N is the total nozzle area in in^2
- V_N is the nozzle velocity in ft/sec
- PD_{Bit} is the bit pressure drop in psi

Calculations for laminar and turbulent flow

Many sets of equations exist for hydraulic parameters using the Bingham and power law models. Two commonly used sets of equations include those sanctioned by the American Petroleum Institute (API) and those that appear in the SPE *Applied Drilling Engineering* textbook. Both sets of equations are valid for fluid behavior in laminar and turbulent flow; the equations differ only in the approach to problem solution. The following sections describe the Bingham, power law, and Herschel-Bulkley (yield-power law [YPL]) models; explain terms used in fluid hydraulics calculations; and give equations for calculating fluid hydraulics.

Methods for Herschel-Bulkley (yield-power law [YPL]) fluids

Hydraulic calculations for Herschel-Bulkley (yield-power law [YPL]) fluids cannot be solved by simple equations. For quick solutions, consult the Baroid hydraulics programs using DFG+ software. DOS and Windows versions of the program are available.

Deriving dial readings

The 600 and 300 rpm readings are back-calculated from the plastic viscosity and yield-point values as shown:

$\theta 300$ = Plastic viscosity + yield point
$\theta 600$ = Yield point + $\theta 300$
$\theta 3$ = 10 second gel (using a hand-crank viscometer)
$\theta 3$ = $\theta 3$ (using a FANN 6-speed viscometer)

API methods (June 1995) for power law fluids

Plastic viscosity, yield point, n and K

High shear rate n and K values can be back-calculated from the 600 and 300 rpm readings and are used for calculations inside the drillpipe.

$$n_p = 3.32 \times \log\left(\frac{\theta 600}{\theta 300}\right)$$

$$K_p = \frac{511 \times \theta 300}{511^{n_p}}$$

Low shear n and K values can be back-calculated from the 100 and 3 rpm readings and are used for calculations in the annulus.

$$n_a = 0.657 \times \log\left(\frac{\theta 100}{\theta 3}\right)$$

$$K_a = \frac{511 \times \theta 3}{5.11^{n_a}}$$

Where

- K_a is the consistency index in the annulus in eq cP
- K_p is the consistency index in the drillpipe in eq cP
- n_a is the flow index in the annulus
- n_p is the flow index in the drillpipe

Fluid velocity

Inside the drillpipe (ft/sec) = $V_p = \dfrac{0.408 \times PO_{GPM}}{ID_{DP}{}^2}$

In the annulus (ft/sec) = $V_a = \dfrac{0.408 \times PO_{GPM}}{ID_{HOLE}^2 - OD_{DP}^2}$

Where

- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches

- PO_{GPM} is the pump output in gal/min
- V_a is the average mud velocity inside the annulus in ft/sec
- V_p is the average mud velocity inside the drillpipe in ft/ sec

Power law for each hydraulic interval

Effective diameter inside the drillpipe (D_{eff})

$$D_{eff} = ID_{DP}$$

Effective diameter in the annulus (D_{eff})

$$D_{eff} = ID_{HOLE} - OD_{DP}$$

Effective viscosity (μ_{ep}) *inside the drillpipe, cP*

$$\mu_{ep} = 100 K_p \left(\frac{96 V_p}{ID_{DP}}\right)^{n_p - 1} \left(\frac{3n_p + 1}{4n_p}\right)^{n_p}$$

Effective viscosity in the annulus (μ_{ea})*, cP*

$$\mu_{ea} = 100 K_a \left(\frac{144 V_a}{ID_{HOLE} - OD_{DP}}\right)^{n_a - 1} \left(\frac{2n_a + 1}{3n_a}\right)^{n_a}$$

Reynolds number (N_{Re})

$$N_{Re} = \frac{928 \times D_{eff} \times V \times \rho_{mud}}{\mu_e}$$

Where

- D_{eff} is the effective diameter of the hole in inches
- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- n_a is the flow index in the annulus
- n_p is the flow index in the drillpipe

- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches
- μ_e is the effective viscosity of the liquid
- ρ_{mud} is the mud density in lb/gal
- V is either V_a for inside annulus or V_p for inside drillpipe
- V_a is the average mud velocity inside the annulus in ft/sec
- V_p is the average mud velocity inside the drillpipe in ft/sec

Friction factor (f)

If the Reynolds number is greater than 2100 the flow is turbulent and the friction factor is:

$$f = \frac{a}{(N_{Re})^b} \quad \text{where } a = \frac{\log n + 3.93}{50} \quad b = \frac{1.75 - \log n}{7}$$

If the Reynolds number is less than 2100 the flow is laminar and the friction factor is:

$$f = \frac{16}{N_{Re}}$$

Pressure loss in the interval (PD_i), psi

$$PD_i = \frac{f \times V^2 \times \rho_{mud}}{25.81 \times D_{eff}} \times L$$

Where

- D_{eff} is the effective diameter of the hole in inches
- f is the friction factor
- ρ_{mud} is the mud density in lb/gal
- V is either V_a for inside annulus or V_p for inside drillpipe

SPE methods for power law fluids

Power Law inside the drillpipe for each hydraulic interval

Average velocity inside the drillpipe (V_p)

$$V_p \text{ (ft/sec)} = \frac{0.408 \times PO_{GPM}}{ID_{DP}^{\;2}}$$

Where

- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- PO_{GPM} is the pump output in gal/min
- V_p is the average mud velocity in the drillpipe in ft/sec

Determine whether the flow is laminar or turbulent

1. Determine N_{Rec} from Figure 9-2 using the lowest values of N_{Re} that intersect the straight line for a given value of n or $N_{Rec} = 2100$.
2. Calculate N_{Rep}.

$$N_{Rep} = \frac{89{,}100 \times \rho_{mud} \times V_p^{\;2-n_p}}{K_p}\left(\frac{0.0416\ ID_{DP}}{3 + 1/n_p}\right)^{n_p}$$

3. If $N_{Rep} < N_{Rec}$, the flow is laminar. If $N_{Rep} \geq N_{Rec}$, the flow is turbulent.

Where

- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- K_p is the consistency index in the drillpipe, eq cP
- ρ_{mud} is the mud density in lb/gal
- n_p is flow index n inside the drillpipe

Turbulent flow pressure drop

Pressure drop (PD_p) inside the drillpipe is then:

$$PD_p = \frac{f_p \times \rho_{mud} \times V_p^{\;2}}{25.8\ ID_{DP}} \times L$$

Where

- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- f_p is the friction factor inside the drillpipe
- L is the length of the drillpipe in feet
- ρ_{mud} is the mud density in lb/gal
- V_p is the average mud velocity inside the drillpipe in ft/sec

Laminar flow pressure drop

Pressure drop inside the drillpipe is then:

$$PD_p = \frac{K_p \times V_p^{\,n_p}\left(\dfrac{3 + 1/n_p}{0.0416}\right)^{n_p}}{144{,}000\ ID_{DP}^{(1 + n_p)}} \times L$$

Where

- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- K_p is the consistency index in the drillpipe in eq cP
- n_p is flow index n inside the drillpipe
- V_p is the average mud velocity inside the drillpipe in ft/sec

Power Law in the annulus for each hydraulic interval

Determine average velocity in the annulus (V_a)

$$V_a\ (\text{ft/sec}) = \frac{0.408 \times PO_{GPM}}{ID_{HOLE}^2 - OD_{DP}^2}$$

Determine whether the flow is laminar or turbulent

1. Determine N_{Rec} from Figure 9-2 using the lowest values of N_{Re} that intersect the straight line for a given value of n or N_{rec} = 2100.
2. Calculate N_{Rea}.

$$N_{Rea} = \frac{109{,}100 \times \rho_{mud} \times V_a^{\,2-n_a}}{K_a}\left(\frac{0.0208\,(ID_{HOLE} - OD_{DP})}{2 + 1/n_a}\right)^{n_a}$$

3. If $N_{Rea} < N_{Rec}$, the flow is laminar. If $N_{Rea} \geq N_{Rec}$, the flow is turbulent.

Turbulent flow pressure drop

Pressure drop in the annulus is then:

$$PD_a = \frac{f_a \times \rho_{mud} \times V_a^{\,2}}{21.1\,(ID_{HOLE} - OD_{DP})} \times L$$

Where

- K_a is the consistency index in the annulus in eq cP
- f_a is the friction factor inside the annulus
- L is the length of the annulus in feet
- ρ_{mud} is the mud density in lb/gal
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches
- PO_{GPM} is the pump output in gal/min
- V_a is the average mud velocity inside the annulus in ft/sec
- n_a is the flow index in the annulus

Laminar flow pressure drop

Pressure drop in the annulus is then:

$$PD_a = \frac{K \times V_a^{\,n_a}\left(\dfrac{2 + 1/n_a}{0.0208}\right)^{n_a}}{144{,}000\,(ID_{HOLE} - OD_{DP})^{(1 + n_a)}} \times L$$

SPE methods for Bingham-plastic fluids

Bingham-plastic inside the drillpipe for each hydraulic interval

Determine average velocity inside the drillpipe (V_p)

$$V_p \text{ (ft/sec)} = \frac{0.408 \times PO_{GPM}}{ID_{DP}^{\,2}}$$

Determine whether the flow is laminar or turbulent

1. Calculate the Hedstrom number in the drillpipe.

$$N_{Hep} = \frac{37{,}000 \times \rho_{mud} \times YP \times ID_{DP}^{2}}{PV^{2}}$$

2. Determine N_{Rec} from Figure 9-3 using the calculated Hedstrom number.
3. Calculate N_{Rep}.

$$N_{Rep} = \frac{928 \times \rho_{mud} \times V_p \times ID_{DP}}{PV}$$

4. If $N_{Rep} < N_{Rec}$, the flow is laminar. If $N_{Rep} \geq N_{Rec}$, the flow is turbulent.

Turbulent flow pressure drop

Pressure drop inside the drillpipe is then:

$$PD_p = \frac{\rho^{0.75} \times V_p^{\,1.75} \times PV^{0.25}}{1800 \times ID_{DP}^{1.25}} \times L$$

Where

- *L* is the length of the drillpipe in feet
- ρ_{mud} is the mud density in lb/gal
- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- PO_{GPM} is the pump output in gal/min

- V_p is the average mud velocity inside the drillpipe in ft/sec
- PV is the plastic viscosity in cP
- YP is the yield point in lb/100 ft^2

Laminar flow pressure drop

Pressure drop inside the drillpipe is then:

$$PD_p = \left(\frac{PV \times V_p}{1500 \times ID_{DP}^2} + \frac{YP}{225 \times ID_{DP}} \right) \times L$$

Bingham plastic in the annulus for each hydraulic interval

Determine average velocity in the annulus (V_a)

$$V_a \text{ (ft/sec)} = \frac{0.408 \times PO_{GPM}}{ID_{HOLE}^2 - OD_{DP}^2}$$

Determine whether the flow is laminar or turbulent

1. Calculate the Hedstrom number in the annulus.

$$N_{Hea} = \frac{24{,}700 \times \rho_{mud} \times YP \times (ID_{HOLE} - OD_{DP})^2}{PV^2}$$

2. Determine N_{Rec} from Figure 9-3 using the calculated Hedstrom number.
3. Calculate N_{Rea}.

$$N_{Rea} = \frac{757 \times \rho_{mud} \times V_a \times (ID_{HOLE} - OD_{DP})}{PV}$$

4. If $N_{Rea} < N_{Rec}$, the flow is laminar. If $N_{Rea} \geq N_{Rec}$, the flow is turbulent.

Turbulent flow pressure drop

Pressure drop in the annulus is then:

$$PD_a = \frac{\rho_{mud}^{0.75} \times V_a^{1.75} \times PV^{0.25}}{1396 \times (ID_{HOLE} - OD_{DP})^{1.25}} \times L$$

Laminar flow pressure drop

Pressure drop in the annulus is then:

$$PD_a = \left(\frac{PV \times V_a}{1000(ID_{HOLE} - OD_{DP})^2} + \frac{YP}{200(ID_{HOLE} - OD_{DP})} \right) \times L$$

Where

- *PV* is the plastic viscosity in cP
- *YP* is the yield point in lb/100 ft^2
- *L* is the length of the drillpipe in feet
- ρ_{mud} is the mud density in lb/gal
- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches
- PO_{GPM} is the pump output in gal/min
- V_a is the average mud velocity in the annulus in ft/sec
- V_p is the average mud velocity inside the drillpipe in ft/sec
- ID_{DP} is the inside diameter of the drillpipe or drill collar in inches
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches

Equivalent circulating density

The following formulas can be used to calculate pressure drop (PD) and equivalent circulating density (ECD).

Where

- PD_a is the pressure drop in the annulus in psi
- n is the number of intervals
- L_i is the length of the interval in feet
- LV_i is the vertical length of the interval in feet
- ρ_{mud} is the density of the mud in lb/gal

The sum of the pressure drops for each annular section (regardless of hole angle) is:

$$PD_a = \sum_{i=1}^{n} PD_i$$

The equivalent circulating density (ECD) for any vertical wellbore is:

$$ECD = \left[\frac{PD_a}{\sum_{i=1}^{n} L_i \times 0.052}\right] + \rho_{mud}$$

In deviated wellbores, the TVD must be taken into account when calculating ECD values. The above equation then becomes:

$$ECD = \left[\frac{PD_a}{\sum_{i=1}^{n} LV_i \times 0.052}\right] + \rho_{mud}$$

Hole cleaning calculations

Particle slip velocity

Chien method (1994)

Particle slip velocity calculations under laminar conditions cannot be solved by a single equation. A 5-step iterative trial-and-error routine is required. **Baroid slip velocity computer programs can solve the equations in a few seconds; the method is outlined here.**

Slip velocity calculations

The general equation for calculating slip velocity for falling particles is:

$$V_s = 12.0\left(\frac{\mu_{eff}}{d \times \rho_f}\right)\left[\sqrt{1 + \left(7.27 \times d \times \left(\frac{\rho_p}{\rho_f} - 1\right)\left(\frac{d \times \rho_f}{\mu_{eff}}\right)^2\right)} - 1\right]$$

Where

- V_s is the laminar slip velocity of the particle in cm/sec
- μ_{eff} is the effective viscosity of the fluid the particle experiences while falling in poise
- d is the average particle diameter in cm
- ρ_f is the density of the drilling fluid in g/cm^3
- ρ_p is the density of the particle in g/cm^3

Mud effective viscosity during particle slip

The variable in the above equation is μ_{eff}, which depends on the mud shear rate experienced by the particle when falling. The following equations are used to calculate μ_{eff}.

Bingham plastic model: $$\mu_{eff} = \frac{\gamma_p}{\gamma} + PV$$

Power law model: $\mu_{eff} = K\gamma^{n-1}$

Herschel-Bulkley model: $\mu_{eff} = \frac{\tau}{\gamma} + K\gamma^{n-1}$
(yield-power law [YPL] model)

Where

- *PV* is the plastic viscosity in cP
- *YP* is the yield point in lb/100 ft^2
- γ is the shear rate in sec^{-1}
- γ_p is the settling shear rate in sec^{-1}
- τ is the calculated shear stress in lb/100 ft^2

Particle settling shear rate

Determine settling shear rate experienced by the falling particle from the calculated slip velocity:

$$\gamma_p = \frac{V_s}{d}$$

Where

- V_s is the slip velocity of the particle in cm/sec
- γ_p is the settling shear rate in sec^{-1}
- *d* is the average particle diameter in cm

To solve for particle slip velocity, follow these steps:

1. Guess the shear rate experienced by the particle when falling.

   Note: Chien states that most drilled particles experience shear rates of 50 sec^{-1} or less.

2. Calculate μ_{eff}.
3. Using μ_{eff} from Step 2, solve for V_s.
4. Using V_s from Step 3, calculate γ_p.

5. If γ_p in Step 4 is very close to the shear rate guessed in Step 1, then the solution is obtained. If γ_p is not close to the shear rate, then reduce the value of the guessed shear rate and repeat Steps 1 through 4.

Note: As the iterative process gets closer to the solution, the differences between γ_p from Step 1 and Step 4 should get smaller. If the differences in successive calculations get larger, then increase the guessed shear rate values.

To determine whether drilled cuttings are falling under laminar or turbulent conditions, first calculate the particle Reynolds number (N_{Res}):

$$N_{Res} = \frac{d \times V_s \times \rho_f}{\mu_{eff}}$$

Where

- μ_{eff} is the effective viscosity of the fluid the particle experiences while falling (poise)
- V_s is the slip velocity of the particle in cm/sec
- *d* is the average particle diameter in cm
- ρ_f is the density of the drilling fluid in g/cm^3

If $N_{Res} < 10$, the particle is falling in laminar slip. If the $N_{Res} > 100$, the particle is falling in turbulent slip, and calculations for turbulent slip are made.

Turbulent slip velocity calculations

Particles falling at high velocities can experience turbulent slip. To determine at which velocity turbulent slip occurs, use the following equation:

$$V_{st} = 32.355 \times \sqrt{d \times \left(\frac{\rho_p}{\rho_f} - 1\right)}$$

Where

- V_{st} is the turbulent slip velocity of the particle in cm/sec
- d is the average particle diameter in cm
- ρ_f is the density of the drilling fluid in g/cm^3
- ρ_p is the density of the particle in g/cm^3

Alternate method for Bingham-plastic fluids

If a computer is not available to perform the Chien method calculations, the following equations can be used to approximate slip velocities in Bingham-plastic fluids.

Laminar slip velocity calculations

$$V_{slip} = \frac{53.3 \times (\rho_{cut} - \rho_{mud}) \times Diam_{cut}^{2} \times V_{ann}}{6.65 \times YP \times (ID_{HOLE} - OD_{DP}) + PV \times V_{ann}}$$

Turbulent slip velocity calculations

$$V_s = 1.06 \times \sqrt{\frac{Diam_{cut} \times ((\rho_{cut} \times 8.345) - \rho_{mud})}{\rho_{mud}}}$$

Where

- V_s is the slip velocity of the particle in cm/sec
- V_{slip} is the slip velocity of the particle in ft/sec
- V_{ann} is the annular velocity in ft/sec
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- $Diam_{cut}$ is the diameter of the drilled cutting in inches
- ρ_{cut} is the density of the drilled cutting in sg
- ρ_{mud} is the mud density in lb/gal
- PV is the plastic viscosity in cP
- YP is the yield point in $lb/100\ ft^2$
- OD_{DP} is the outside diameter of the drillpipe or drill collar in inches

Cuttings transport efficiency calculations

Vertical holes

Cuttings transport efficiency in vertical holes is commonly calculated by:

$$TE\ (\%) = \left(\frac{V_a - V_{slip}}{V_a}\right) \times 100$$

Where

- V_{slip} is the slip velocity of the particle in ft/sec
- V_a is the annular velocity in ft/sec

In these calculations, the effect of reduced mud viscosity caused by mud flow is usually neglected. It is important that V_a and V_{slip} have identical units (for example, ft/min or cm/sec).

High angle or horizontal holes

In deviated or horizontal holes, cuttings transport efficiency is not easy to calculate because the mud velocity distribution under the eccentric drillpipe and the corresponding effect of changes in mud shear rates under the drillpipe must be considered. **To calculate cuttings transport efficiency in deviated or horizontal holes, use the Baroid hole cleaning computer programs.**

MAXROP calculations

Calculations can be made to estimate the maximum rate of penetration while maintaining good hole cleaning. A limit of 5 percent by volume cuttings in the annulus has been recommended in the literature. However, many

operators recommend a maximum cuttings concentration of 4 percent by volume.

Note: The following calculations assume there is a concentric drillpipe.

Vertical holes

$$\text{MAXROP(ft/hr)} = \frac{CC \times V_a \times TE \times (ID_{HOLE}^2 - OD_{DP}^2)}{ID_{HOLE}^2 \times (100 - CC)} \times 3600$$

Where

- *CC* is the cuttings concentration in the annulus percent by volume, using 5 maximum
- V_a is the average annular velocity in ft/sec
- *TE* is the cuttings transport efficiency in percent
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the drillpipe diameter in inches

Vertical holes underreamed to a larger diameter

$$\text{MAXROP(ft/hr)} = \frac{CC \times V_a \times TE \times (UD^2 - OD_{DP}^2)}{(UD^2 - ID_{HOLE}^2) \times (100 - CC)} \times 3600$$

Where

- *CC* is the cuttings concentration in the annulus percent by volume
- V_a is the average annular velocity in ft/sec
- *TE* is the cuttings transport efficiency in percent
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the drillpipe diameter in inches
- *UD* is the underreamer diameter in inches

Cuttings concentration in the annulus for a given penetration rate

Cuttings concentration at a given penetration rate can be determined using the following equations.

Vertical holes

$$CC\ (\%\ v/v) = \frac{ROP \times ID_{HOLE}^2 \times (100 - CC)}{V_a \times TE \times (ID_{HOLE}^2 - OD_{DP}^2) \times 3600}$$

Where

- *CC* is the cuttings concentration in the annulus percent by volume
- V_a is the average annular velocity in ft/sec
- *ROP* is the penetration rate in ft/hr
- *TE* is the cuttings transport efficiency in percent
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the drillpipe diameter in inches

Vertical holes underreamed to a larger diameter

$$CC\ (\%\ v/v) = \frac{ROP \times (UD^2 - ID_{HOLE}^2) \times (100 - CC)}{V_a \times TE \times (UD^2 - OD_{DP}^2) \times 3600}$$

Where

- *CC* is the cuttings concentration in the annulus percent by volume
- V_a is the average annular velocity in ft/sec
- *ROP* is the penetration rate in ft/hr
- *TE* is the cuttings transport efficiency in percent
- ID_{HOLE} is the diameter of hole or inside diameter of casing in inches
- OD_{DP} is the drillpipe diameter in inches
- *UD* is the underreamer diameter in inches

Annular mud density increase

The annular mud density increase due to cuttings at a given penetration rate can by calculated by:

$$MW_{ann} = \frac{(\rho_f \times (100 - CC)) + (\rho_p \times CC \times 8.345)}{100}$$

Where

- ρ_f is the mud density of the drilling fluid in lb/gal
- ρ_p is the density of the drilled cutting in g/cm^3
- *CC* is the cuttings concentration in the annulus percent by volume

List of terms

a	Coefficient in friction factor calculations
A_N	Nozzle area of bit, in^2
A_{Bit}	Area of bit
b	Exponential coefficient in friction factor calculations
BU	Bottoms-up circulating time, min
CC	Cuttings concentration in the annulus, % v/v
C_T	Capacity of drillpipe and drill collars, bbl
d	Average particle diameter, cm
D	Diameter, in
D_i	Interval displacement of the drillpipe or drill collars, bbl
D_{eff}	Effective diameter of hole
$Diam_{cut}$	Diameter of the drilled cutting, in or cm
ECD	Equivalent circulating density, lb/gal or sg
f	Friction factor
f_a	Friction factor in the annulus
f_p	Friction factor inside the drillpipe
HHP_{bit}	Hydraulic horsepower at the bit, hp
ID_{DP}	Inside diameter drillpipe, in
ID_{HOLE}	Inside diameter of Hole, in
Imp_{Bit}	Jet impact force at the bit, lb/ft
Jet_i	Jet nozzle diameter, 32nds in
K	Consistency index

K_a	Consistency index K in the annulus, eq cP
K_p	Consistency index K inside the drillpipe, eq cP
L	Length, ft
L_i	Interval length, ft
LV_i	Vertical interval length, ft
LSR YP	Low shear rate YP, lb/100 ft^2 or Pa
n	Flow index
n_a	Flow index n in the annulus
N_{He}	Hedstrom number
n_p	Flow index n inside the drillpipe
N_{Re}	Reynolds number
N_{Rea}	Reynolds number in the annulus
N_{Rec}	Critical Reynolds number
N_{Rep}	Reynolds number inside the drillpipe
N_{Res}	Reynolds number of a falling particle
OD_{DP}	Outer diameter of drillpipe, in
OD_{HOLE}	Outer diameter (hole diameter), in
PD	Total pressure drop in an annulus, psi
PD_a	Pressure drop in the annulus, psi
PD_{bit}	Pressure drop at the bit, psi/ft
PD_p	Pressure drop inside the drillpipe, psi
PO_{BPM}	Pump output, bbl/min
PO_{GPM}	Pump output, gal/min
$Press_{pump}$	Pump pressure, psig
PV	Plastic viscosity (Bingham-plastic model), cP
TCT	Total circulating time, min
TE	Cuttings transport efficiency, %
TVD	True vertical depth, ft or m
UD	Underreamer diameter, in
V	Average mud velocity V_a in the annulus and V_p in the drillpipe, ft/sec
V_i	Interval length, ft
V_a	Average mud velocity in the annulus, ft/sec
V_{Ann_I}	Annular volume of the interval, bbl
$V_{Ann_{Total}}$	Total annular volume of the interval, bbl
V_{Hole_I}	Hole volume of the interval, bbl

V_N	Nozzle velocity, ft/sec
V_p	Average mud velocity inside the drillpipe, ft/sec
V_{Pits}	Volume of pits, bbl or m^3
V_s	Slip velocity of falling particle, cm/sec
V_{st}	Turbulent slip velocity of falling particle, cm/sec
V_{slip}	Slip velocity of falling particle, ft/sec
YP	Yield point, lb/100 ft^2
YPL	Yield-power law (Herschel-Bulkley) rheological model
γ	Shear rate, sec^{-1}
γ_p	Shear rate experienced by falling particle, sec^{-1}
ϵ	Drillpipe eccentricity
θ	Viscometer dial reading at a particular operating speed
μ_e	Effective viscosity, cP
μ_{ea}	Effective viscosity in the annulus, cP
μ_{eff}	Effective viscosity experienced by settling particle, cP
μ_{ep}	Effective viscosity inside the drillpipe, cP
ρ_{cut}	Density of the drilled cutting, sg
ρ_f	Density of drilling fluid, g/cm^3
ρ_{mud}	Mud weight, lb/gal
ρ_p	Density of the particle, g/cm^3
τ	Shear stress, lb/100 ft^2 or Pa
τ_y	Yield stress, lb/100 ft^2 or Pa
τ_0	Yield stress at zero shear rate, lb/100 ft^2 or Pa

CHAPTER 10

Solids control

The Complete Fluids Company

Contents

Overview

Solids control is the process of controlling the buildup of undesirable solids in a mud system. The buildup of solids has undesirable effects on drilling fluid performance and the drilling process. Rheological and filtration properties can become difficult to control when the concentration of drilled solids (low-gravity solids) becomes excessive. Penetration rates and bit life decrease and hole problems increase with a high concentration of drill solids.

Solids-control equipment on a drilling operation should be operated like a processing plant. In an ideal situation, all drill solids are removed from a drilling fluid.

Under typical drilling conditions, low-gravity solids should be maintained below 6 percent by volume.

Sources and sizes of solids

The two primary sources of solids (particles) are chemical additives and formation cuttings. Formation cuttings are contaminants that degrade the performance of the drilling fluid. If the cuttings are not removed, they will be ground into smaller and smaller particles that become more difficult to remove from the drilling fluid.

Most formation solids can be removed by mechanical means at the surface. Small particles are more difficult to remove and have a greater effect on drilling fluid properties than large particles. The particle size of

drilled solids incorporated into drilling fluid can range from 1 to 250 microns (1 micron equals 1/25,400 of an inch or 1/1,000 of a millimeter). Table 10-1 lists the approximate sizes of contaminating solids.

Material	Diameter, microns	Screen mesh required to remove	Diameter, inches
Clay Colloidals Bentonite	1	—	0.00004
	5	—	0.0002
Silt Barites Fine cement dust	44 -6	1,470-400	0.0004 -0.0015
Fine sand	44	325	0.0015
	53	270	0.002
	74	200	0.003
API sand	105	140	0.004
	149	100	0.006
Coarse sand	500	35	0.020
	1,000	18	0.040

Table 10-1: Solids sizes. Common solids found in drilling fluids range in size from 1 to 1,000 microns.

Mechanical solids-removal equipment

One method of solids control is the use of mechanical solids-removal equipment. Another method, dilution, is discussed later in this chapter.

Equipment that removes solids mechanically can be grouped into two major classifications:

- Screen devices
- Centrifugal separation devices

Table 10-2 identifies the particle sizes (in microns) the equipment can remove.

Solids-control equipment	Particle sizes removed
Screen devices	61 micron cut with 250-mesh screen
Centrifugal separation devices • Decanting centrifuges • Hydrocyclones	 Colloidal solids to 5 micron 20-70 micron solids, depending on cone size

Table 10-2: Solids-control equipment and effective operating ranges in microns. The particle size removed depends on the type of solids-control equipment.

Screen devices

The most common screen device is a shale shaker, which contains one or more vibrating screens that mud passes through as it circulates out of the hole. Shale shakers are classified as circular/elliptical or linear motion shale shakers.

- **Circular/elliptical motion shaker.** This shaker uses elliptical rollers to generate a circular rocking motion to provide better solids removal through the screens.
- **Linear motion shaker.** This shaker uses a straight forward-and-back rocking motion to keep the fluid circulating through the screens.

Screen effectiveness

Two factors that determine the effectiveness of a screen are mesh size and screen design.

Mesh size. The screen opening size determines the particle size a shaker can remove. Screen mesh is the number of openings per linear inch as measured from the center of the wire. For example, a 70 by 30 oblong mesh screen (rectangular opening) has 70 openings

along a one-inch line one way and 30 openings along a one-inch line perpendicular to the first.

Actual separation sizes are determined by factors such as particle shape, fluid viscosity, feed rates, and particle cohesiveness. Some muds can form a high surface-tension film on the wires of the screen and reduce the effective opening size of the screen. Tables 10-3 and 10-4 list specifications for different screen sizes and mesh shapes.

Square mesh screens				
	Wire diameter	**Opening width**		
Mesh	**Inches**	**Inches**	**Microns**	**Percent open area**
20 × 20	0.016	0.0340	863	46.2
30 × 30	0.013	0.0203	515	37.1
40 × 40	0.010	0.0150	381	36.0
50 × 50	0.009	0.0110	279	30.3
60 × 60	0.0075	0.0092	234	30.5
80 × 80	0.0055	0.0070	178	31.4
100 × 100	0.0045	0.0055	140	30.3
120 × 120	0.0037	0.0046	117	30.5
150 × 150	0.0026	0.0041	104	37.4
170 × 170	0.0024	0.0035	89	35.1
200 × 200	0.0021	0.0029	74	33.6
250 × 250	0.0016	0.0024	61	36

Table 10-3: Square mesh screens. This table provides specifications for square mesh screens of different sizes.

Oblong mesh screens				
	Wire diameter	Opening width/length		
Mesh	Inches	Inches	Microns	Percent open area
20 × 30	0.014	0.036/0.0193	914/490	41.8
20 × 40	0.013	0.037/0.012	940/305	35.6
20 × 60	0.009	0.041/0.0076	1,041/193	34.0
40 × 60	0.009	0.016/0.0076	406/193	29.4
40 × 80	0.0075	0.0181/0.0055	457/140	35.6

Table 10-4: Oblong mesh screens. This table provides specifications for common oblong mesh screens of different sizes.

Screen design. Screens are available in two- and three-dimensional designs.

Two-dimensional screens can be classified as:

- Panel screens, with two or three layers bound at each side by a one-piece, double-folded hook strip
- Perforated plate screens, with two or three layers bonded to a perforated, metal plate that provides support and is easy to repair

Three-dimensional screens are perforated, plate screens with a corrugated surface that runs parallel to the flow of fluid. This configuration provides more screen area than the two-dimensional screen configuration. The different types of three-dimensional screens are:

- Pyramid
- Plateau

Figure 10-1 shows the difference between two- and three-dimensional screens.

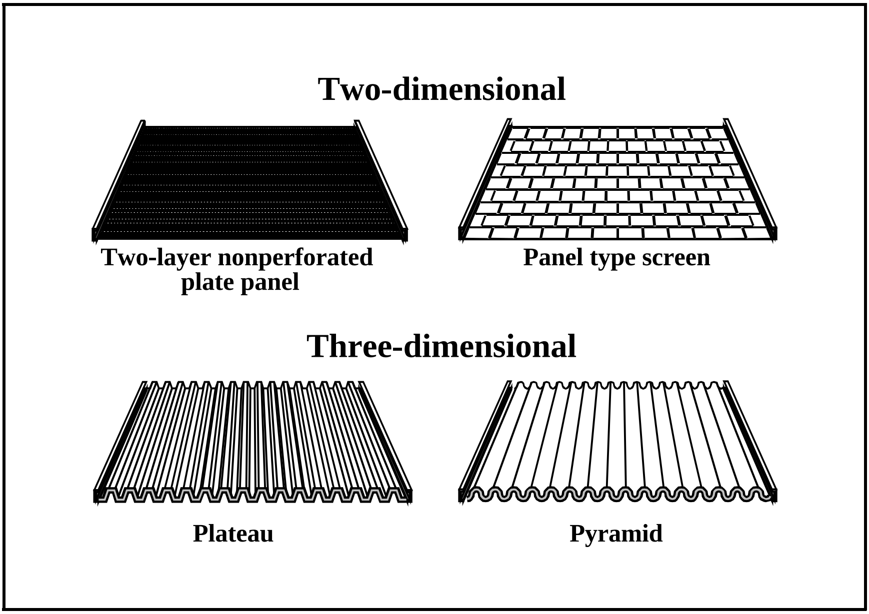

Figure 10-1: The difference between two- and three-dimensional screens. A three-dimensional screen provides areas for the removed solids to gather and be removed without blocking the screening area.

Screen designations

The API (RP13E) recommends that all screens be labeled with the screen name, separation potential, and flow capacity. Optional screen labels include U.S. sieve number, aspect ratio, and transmittance. Table 10-5 depicts how screens can be labeled using all descriptors.

Screen name	U.S. sieve no.	Separation potential, microns			Flow capacity		As-pect ratio	Trans-mit-tance
		d_{50}	d_{16}	d_{84}	Cond	Area		
Pyramid PMD DX 50	48	318	231	389	6.10	7.42	1.45	45.3
Flat PI	47	327	231	349	8.85	7.28	1.43	64.4

Table 10-5: Industry-recommended screen-labeling method. The industry method provides a way to compare screens.

The following definitions apply to Table 10-5.

Separation potential. The percentage of particles of the specific size, in microns, that can be removed.

Examples:

d_{50} Particle size in microns where 50 percent of the particles are removed

d_{16} Particle size in microns where 16 percent of the particles are removed

d_{84} Particle size in microns where 84 percent of the particles are removed

Note: d_{50} is listed first in most tables because it is the most common.

Figure 10-2 demonstrates separation potential.

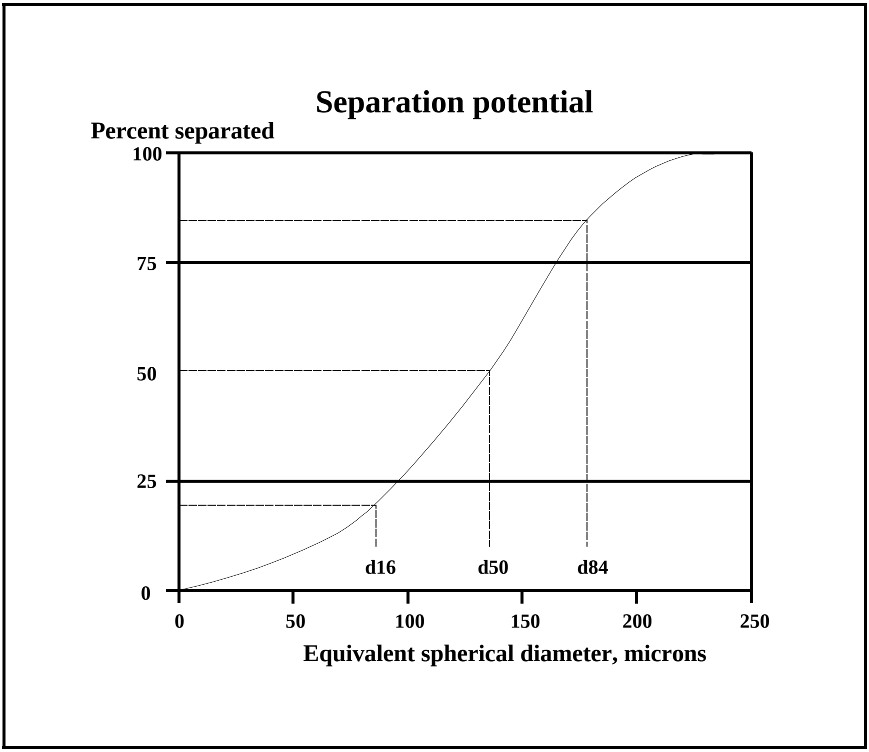

Figure 10-2: Separation potential. The percentage of microns removed increases as the equivalent spherical diameter of particles increases.

Flow capacity. The two parts of flow capacity include conductance (Cond) and nonblanked (open space) area (Area).

Conductance is the amount of open space between wires in kilodarcies per millimeter.

The nonblanked (open space) area is the total effective screening area per panel in square feet.

Aspect ratio. The volume-weighted average length-to-width of the screen openings.

Transmittance. The net flow capacity of individual screens; the product of conductance and unblocked screening area.

Centrifugal separation devices

The two types of centrifugal separation devices are:

- Decanting centrifuges
- Hydrocyclones

Decanting centrifuges

A decanting centrifuge consists of a conical, horizontal steel bowl that rotates at high speed using a double screw-type conveyor. The conveyor rotates in the same direction as the outer bowl but at a slightly slower speed (Figure 10-3). An important aspect of centrifuge operation is the dilution of the slurry being fed into the unit. The slurry dilution reduces the feed viscosity and maintains the separation efficiency of the machine. The higher the viscosity of the base mud, the more dilution is needed (2 to 4 gallons of water per minute is common). The effluent (liquid output from the centrifuge) viscosity should be 35 to 37 seconds per quart for efficient separation. If the viscosity falls below 35 seconds per quart, too much water is being added. This will cause turbulence within the bowl and reduce efficiency. Manufacturers' recommendations concerning mud-feed rates and bowl speeds should be followed closely.

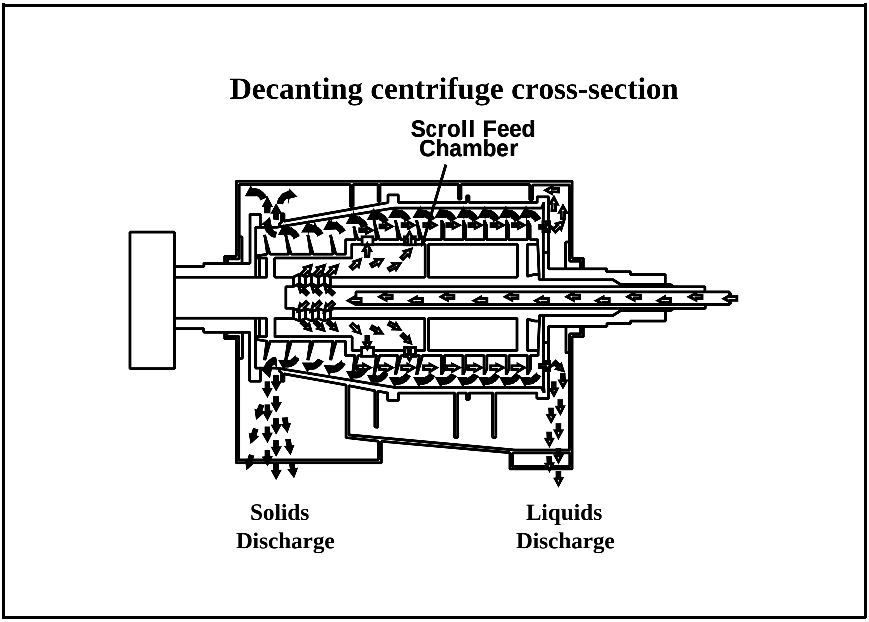

Figure 10-3: Cross-section of a decanting centrifuge. In this diagram, open arrows indicate the path of liquids; solid arrows indicate the path of solids.

A single centrifuge unit set for total solids discard should be used for low-density systems. The primary function of a centrifuge is not to control total percent solids in a system, but rather to maintain acceptable and desirable flow properties in that system. Two centrifuges operating in series are recommended for the following systems:

- Invert emulsion (i.e., synthetic and oil-based systems)
- High-density, water-based systems
- Water-based systems in which base fluid is expensive (i.e., brines)
- Closed loop

- Zero discharge

The first centrifuge unit is used to separate barite and return it to the mud system. The second unit processes the liquid overflow from the first unit, discarding all solids and returning the liquid portion to the mud system.

Note: Centrifuge efficiencies are influenced by mud weight and mud viscosity. During centrifuge operation, the underflow should be analyzed regularly to determine the amount of low-gravity solids and barite being removed and retained.

Hydrocyclones

Hydrocyclones, classified as desanders or desilters, are conical solids separation devices in which hydraulic energy is converted to centrifugal force. Mud is fed by a centrifugal pump through the feed inlet tangentially into the feed chamber. The centrifugal forces thus developed multiply the settling velocity of the heavier-phase material, forcing it toward the wall of the cone. The lighter particles move inward and upward in a spiraling vortex to the overflow opening at the top. The discharge at the top is the overflow or effluent; the discharge at the bottom is the underflow. The underflow should be in a fine spray with a slight suction at its center. A rope discharge with no air suction is undesirable. Figure 10-4 illustrates the hydrocyclone process.

The sizes of the cones and the pump pressure determine the cut obtained. Lower pressures result in coarser separation and reduced capacity. Figure 10-5 shows the equivalent particle-size cut (in microns) of different diameter cones.

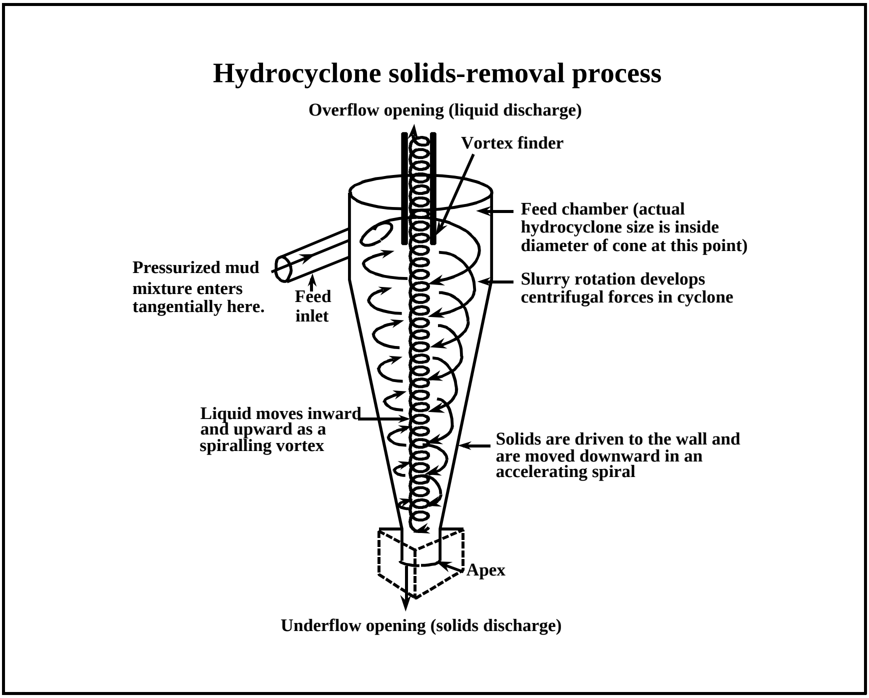

Figure 10-4: Hydrocyclone solids-removal process. A hydrocyclone can process large volumes of mud due to its upright spiral design.

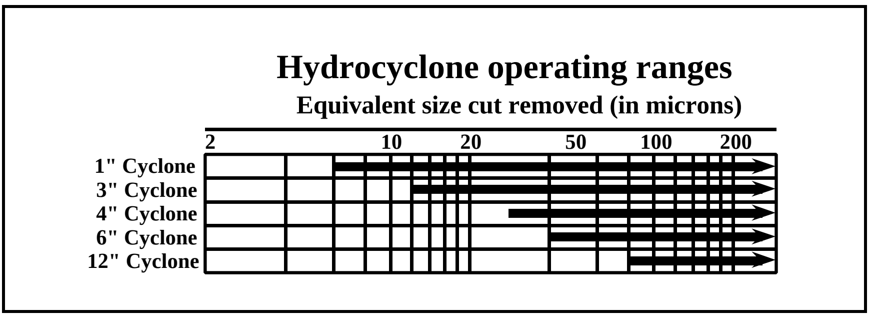

Figure 10-5: Hydrocyclone operating range chart. Cyclones remove roughly the same size particles; large cyclones can handle much larger volumes of drilling fluid.

Hydrocyclones are either desanders or desilters.

Desanders. Desanders consist of a battery of 6-inch or larger cones. Even though desanders can process large volumes of mud per single cone, the minimum size particles that can be removed are in the range of 40 microns (with 6-inch cones).

Desilters. Desilters consist of a battery of 4-inch or smaller cones. Depending on the size of the cone, a particle size cut between 6 and 40 microns can be obtained.

Even though hydrocyclones are effective in removing solids from a drilling fluid, their use is not recommended for fluids that contain significant amounts of weighting materials or muds that have expensive fluid phases. When hydrocyclones are used with these fluids, not only will undesirable drilled solids be removed, but also the weight material along with base fluid, which can become cost-prohibitive.

Mud cleaner. The mud cleaner is a solids separation device that combines a desilter with a screen device. The mud cleaner removes solids using a two-stage process. First, the drilling fluid is processed by the desilter. Second, the discharge from the desilter is processed by a high-energy, fine-mesh screen shaker. This method of solids removal is recommended for muds containing significant amounts of weighting materials or having expensive fluid phases.

Note: When recovering weight material with a mud cleaner, be aware that any fine solids that go through the cleaner's screen are also retained in the mud. Over time, this process can lead to a fine-solids buildup.

Dilution

Dilution, or the addition of base fluid to a mud system, serves to:

- Reduce concentration of solids left by mechanical solids-removal equipment
- Replenish liquids lost when using mechanical solids-control equipment

Dilution can generate excessive volumes, however, the disposal and clean-up costs can be very expensive.

Calculating the efficiency of solids-control equipment

Evaluate the performance of solids control equipment by the:

- Efficiency of drill-solids removal
- Efficiency of liquid conservation

Solids-removal efficiency is the percent of the drill solids removed from the active mud system by methods other than dilution or dumping. The discharge is assumed to consist of whole mud and drill solids. The fraction of whole mud in the discharge indicates the degree of liquid conservation.

API Method (March 1996) for determining drilled solids system performance

Objective

Determine the drilled solids removal efficiency for a given interval by a set of drilling fluid processing equipment.

Unit

%

Example

Solids removal performance (SP) = 50%

Equipment

- Density measuring equipment (see Chapter 5-Field Tests, Density: Baroid mud balance)
- Retort equipment (see Chapter 5-Field Tests, Retort analysis)
- Chloride content equipment (see Chapter 5-Field Tests, Chloride content)

Procedure

1. Measure and record all suction pit mud weight, salinity, and solids (retort) data for subject interval.
2. Measure and record base fluid additions to the mud (V_{bf}).
3. Determine the base fluid fraction, F_{bf} (average value for the interval in question, determined by retort and salt measurement).
4. Determine drilled solids fraction, F_{ds} (average value for the interval in question, determined by retort measurement and corrected for salt and bentonite concentration).

Note: Use identical averaging methods for steps 3 and 4, different averaging methods can result in inaccurate comparisons.

5. Calculate the volume of mud built (V_{mb})

$$V_{mb} = V_{bf} / F_{bf}$$

Where

V_{mb} is the volume of mud built
V_{bf} is the volume of the base fluid added to the drilling system
F_{bf} is the base fluid fraction

6. Calculate the excavated volume of solids drilled, V_{ds} (calculated from the dimensions of the wellbore, that is, length and diameter)

7. Calculate the total dilution, D_t (total dilution is the volume of mud that would be built if there was no solids removal equipment)

$$D_t = \frac{V_{ds}}{F_{ds}}$$

Where

D_t is the total dilution
V_{ds} is the volume of the drilled solids added to the drilling system
F_{ds} is the drilled solids fraction

8. Calculate the dilution factor, DF (dilution factor is the ratio of the volume of mud built to total dilution)

$$DF = \frac{V_{mb}}{D_t}$$

Where

DF is the dilution factor
V_{mb} is the volume of mud built
D_t is the total dilution

9. Calculate the drilled solids performance (SP)

$$SP = (1\text{-}DF)(100)$$

Where

SP is the drilled solids removal performance
DF is the dilution factor

API Method (March 1996) for determining cost effectiveness of solids control equipment

Objective

Determine the cost effectiveness of individual pieces of solids control equipment when using a water-based mud. This procedure may be adapted to oil-based muds.

Equipment

- Density measuring equipment (see Chapter 5-Field Tests, Density: Pressurized mud balance, Fann convertible or Halliburton Tru-wate cup)
- Retort equipment (see Chapter 5-Field Tests, Retort analysis)
- Bentonite determination equipment (see Chapter 5-Field Tests, Methylene blue test (MBT))
- Chloride content equipment (see Chapter 5-Field Tests, Chloride content)

Procedure

1. Determine the daily operating time of the piece of equipment. Record as A, hr/day.
2. Measure the equipment discard flow rate. Record as B, gal/min.
3. Measure the discard density with the pressurized mud balance. Record as C, lb/gal.
4. Determine the volume percent solids in the discard stream with retort. Record as D, %.

5. Determine the equivalent bentonite content in the drilling fluid from the mud report or measure using the methylene blue test. Record as E, lb/bbl.
6. Determine the chloride ion content of the drilling fluid from the mud report or measure the chloride ion using the chloride test. Record as F, mg/L.
7. Obtain the desired volume percent drilled solids content of the drilling fluid. Record as G,%.
8. Obtain the drilled solids density from the mud report or measure with a retort. Record as a, g/cm^3.
9. Obtain the density of the weighting material. Record as b, g/cm^3.
10. Obtain the drilling fluid costs. Record as H, $/bbl, £/m^3 or currency of choice.
11. Obtain the drilling fluid liquid phase costs. Record as H', in currency of choice/bbl, or m^3.
12. Obtain the weighting material costs. Record as I, in currency of choice/bbl, or m^3.

Note: This is the cost of a barrel of weighting material not the cost of weighting material per barrel.

13. Obtain the costs of the chemicals in the drilling fluid. Record as J, in currency of choice/bbl, or m^3.
14. Obtain the rental equipment costs. Record as K, in currency of choice/day.
15. Obtain the costs of waste disposal. Record as c, in currency of choice/bbl, or m^3.

Note: The cost to dispose of excess drilling fluid and discard stream may be different.

Calculate discard stream composition

16. Calculate the corrected liquid content of the discard stream.

$$L\ (\%) = (100 - D)(1 + 5.88 \times 10^{-8} \times F^{1.2})$$

Where

L is the corrected liquid content in the discard stream
D is the volume percent solids in the discard stream
F is the chloride ion content

Note: The preceding equation corrects the solids content of the discard stream for salt in the form of sodium chloride only. If other salts are present as the dominate salt, different equations must be used to compensate for their presence.

17. Calculate the corrected solids content of the discard stream.

$$M\ (\%) = 100 - L$$

Where

M is the corrected solids content of the discard stream
L is the corrected liquid content in the discard stream

18. Calculate the density of the liquid phase in the discard stream.

$$N\ (g/cm^3) = 1 + 1.94 \times 10^{-5} \times F^{0.95}$$

Where

N is the density of the liquid phase of the discard stream
F is the chloride ion content

19. Calculate the density of the solids in the discard stream.

$$O\ (g/cm_3) = \frac{12 \times C - L \times N}{M}$$

Where

O is the density of the solids in the discard stream

N is the density of the liquid phase of the discard stream

M is the corrected solids content of the discard stream

L is the corrected liquid content in the discard stream

C is the density of the discard stream

20. Calculate the weighting material content of the discard stream.

$$P \text{ (lb/bbl)} = \frac{3.5 \times b \times M \times (O - a)}{b - a}$$

Where

P is the weighting material content of the discard stream

O is the density of the solids in the discard stream

M is the corrected solids content of the discard stream

b is the density of the weighting material

a is the drilled solids density

$$Q\ (\%) = \frac{P}{(3.5 \times b)}$$

Where

Q is the percentage of weighting material content of the discard stream

P is the weighting material content of the discard stream

b is the density of the weighting material

21. Calculate the low gravity solids content of the discard stream.

R (%) = M - Q

Where

R is the percentage of low gravity solids content of the discard stream
M is the corrected solids content of the discard stream
Q is the percentage of weighting material content of the discard stream

22. Calculate the drilled solids content of the discard stream adjusted for bentonite content.

$$S\ (\%) = R - \frac{E}{9.1}$$

Where

S is the drilled solids content of the discard stream adjusted for bentonite content
R is the percentage of low gravity solids content of the discard stream
E is the equivalent bentonite content in the drilling fluid

$$T\ (\text{lb/bbl}) = 3.5 \times S \times a$$

Where

T is the drill solids content of the discard stream
S is the drilled solids content of the discard stream adjusted for bentonite content
a is the drilled solids density

Cost comparison

1. Calculate the total volume discarded per day by the piece of equipment being evaluated.

$$U\ (\text{bbl/day}) = A \times B \times (60/42)$$

Where

U is the total volume discarded each day by each piece of equipment
A is the daily operating time of the piece of equipment
B is equipment discard flow rate

2. Calculate the volume of the liquid in the discard stream.

$$V\ (\text{bbl/day}) = U \times [(100 - M)/100]$$

Where

V is the volume of liquid in the discard stream
U is the total volume discarded each day by each piece of equipment
M is the corrected solids content of the discard stream

3. Calculate the volume of the drilled solids in the discard stream.

$$W\ (\text{bbl/day}) = \frac{U \times S}{100}$$

Where

W is the volume of drilled solids in the discard stream
U is the total volume discarded each day by each piece of equipment
S is the drilled solids content of the discard stream adjusted for bentonite content

4. Calculate the volume of the weighting material in the discard stream.

$$X\ (\text{bbl/day}) = \frac{U \times Q}{100}$$

Where

X is the volume of the weighting material in the discard stream

U is the total volume discarded each day by each piece of equipment
Q is the percentage of weighting material content of the discard stream

5. Calculate the cost of the weighting material in the discard stream.

$$Y = X \times I$$

Where

Y is the cost of the weighting material in the discard stream.
X is the volume of the weighting material in the discard stream
I is the cost of the weighting material

6. Calculate the cost of the chemicals in the discard stream.

$$Z = V \times J$$

Where

Z is the cost of the chemicals in the discard stream
V is the volume of liquid in the discard stream
J is the cost of the chemicals in the drilling fluid

7. Calculate the cost of the liquid in the discard stream.

$$Z''' = V \times H'$$

Where

Z''' is the cost of the liquid in the discard stream
V is the volume of liquid in the discard stream
H' is the cost of the drilling fluid liquid phase

8. Calculate the cost to dispose of the discard stream.

Z” = U × c

Where

Z” is the cost to dispose of the discard stream
U is the total volume discarded each day by each piece of equipment
c is the cost of waste disposal

9. Calculate the total cost for using the piece of equipment being evaluated.

A = K + Y + Z + Z” + Z”’

Where

A is the total cost for using the piece of equipment being evaluated
Y is the cost of the weighting material in the discard stream
K is the rental cost of the equipment
Z is the cost of the chemicals in the discard stream
Z” is the cost to dispose of the discard stream
Z”’ is the cost of the liquid in the discard stream

10. Calculate the dilution volume required to dilute out an equivalent volume of drilled solids.

B’ (bbl) = (100W/G) -W

Where

B’ is the dilution volume required to dilute out an equivalent volume of drilled solids
W is the volume of drilled solids in the discard stream
G is the desired volume percent drilled solids content of the drilling fluid

12. Calculate the cost to implement dilution, including costs to dispose of excess fluid.

$$C = B' \times (H + c)$$

Where

C is the cost to implement dilution, including costs to dispose of excess fluid

B' is the dilution volume required to dilute out an equivalent volume of drilled solids

H is the drilling fluid costs

c is the cost of waste disposal of drilling fluids

13. The operation of the equipment can be considered cost effective if:

$$A < C$$

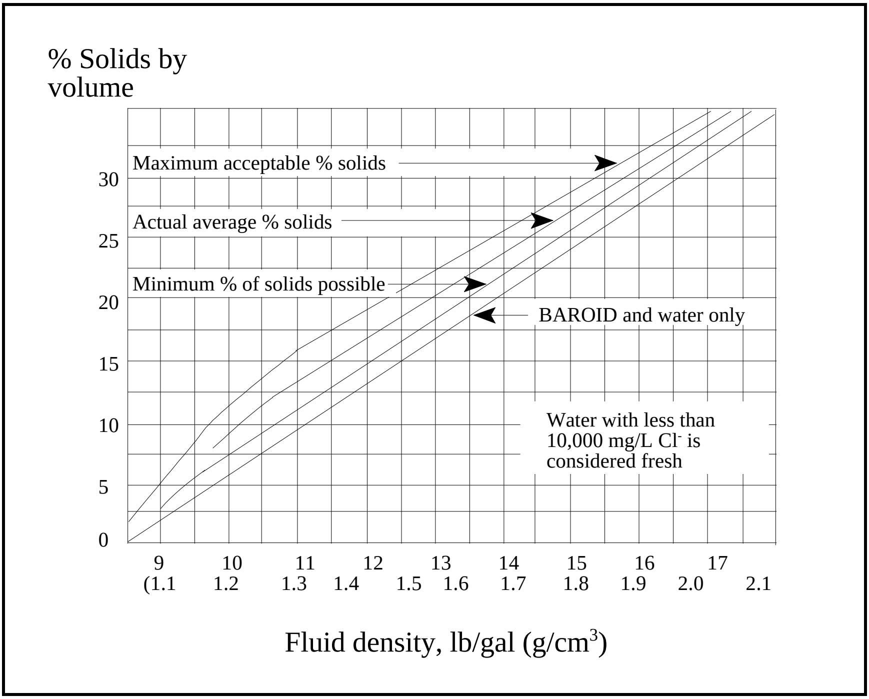

Figure 10-6: Fluid density vs % solids by volume in a water-based mud. Maximum, actual and minimum acceptable solids in a water-based mud.

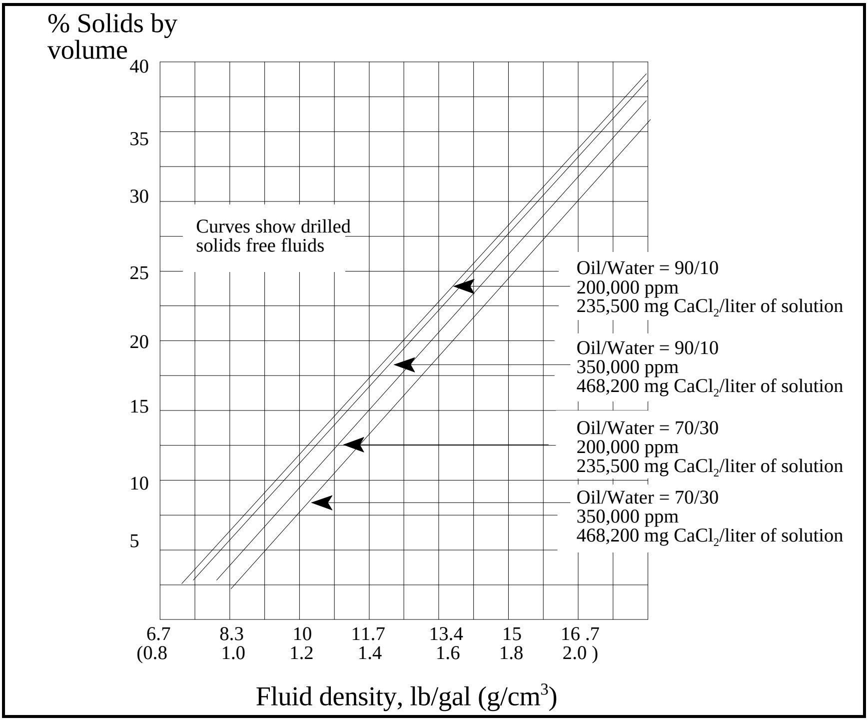

Figure 10-7: Fluid density vs % by volume undissolved solids in a oil-based mud. Solids content at varying oil/water ratios and $CaCl_2$ concentrations.

CHAPTER 11

Specialized tests

The Complete Fluids Company

Contents

Overview

Specialized tests are performed in the laboratory with equipment that is either too large or too sensitive to be used at the wellsite. These tests are used to evaluate:

- Mud stability
- Filtration control
- Shale characteristics
- Fluid lubricity
- The particle size of mud solids
- Relative aromatic content
- Formation damage

This chapter describes a number of specialized tests.

Rheology and suspension tests

Three specialized tests designed to measure the rheological and suspension properties of a drilling fluid are :

- FANN 50 test
- FANN 70 test
- High angle sag test (HAST)

FANN 50 test

Description. The FANN 50, an HTHP viscometer, is used to evaluate rheological properties at up to 500°F (260°C) and 1,000 psi (6,895 kPa) to determine temperature stability of a drilling fluid. This test is especially useful in determining whether high temperature flocculation occurs in water-based muds.

Interpretation. FANN 50 test results are presented graphically by plotting the change in viscosity with respect to temperature over the heating and cooling cycle (Figure 11-1). When the viscosity of the drilling fluid increases dramatically as the temperature increases, the test results indicate temperature instability.

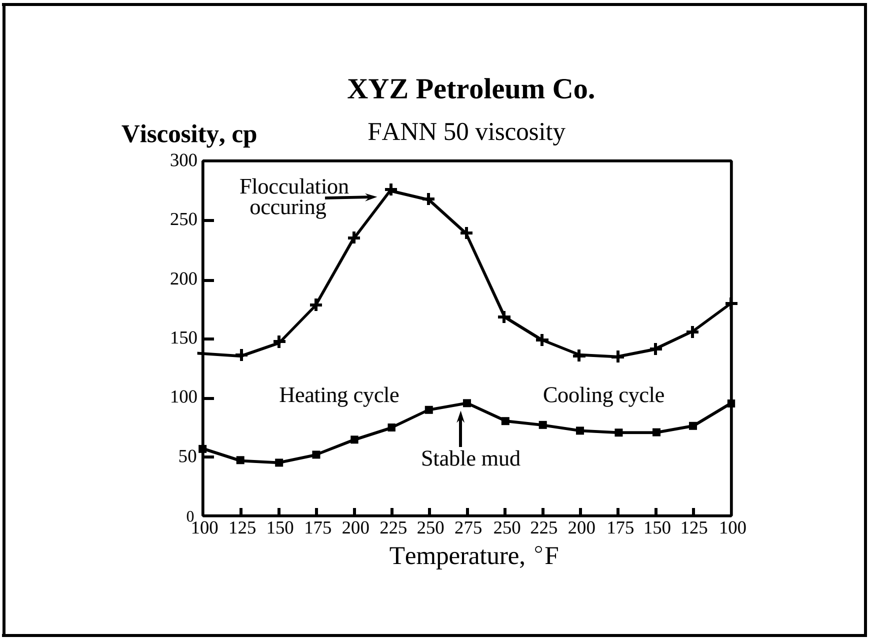

Figure 11-1: FANN 50 test results. A dramatic increase in viscosity in conjunction with an increase in temperature indicates temperature instability.

FANN 70 test

Description. The FANN 70, an HTHP viscometer, is used to determine the rheological properties of drilling fluids subjected to temperatures up to 500°F (260°C) and pressures up to 20,000 psi (137,895 kPa). Because

oils and esters are compressible, the viscosity of fluids prepared with these base fluids is directly affected by operating pressures. The FANN 70 test is run when downhole settling or ineffective hole cleaning is suspected.

Interpretation. Results are presented in Table 11-1 that include all standard rheological properties plus Tau 0 (τ_0), n, and K. A Tau 0 below 6 may indicate a hole cleaning or suspension problem .

Temperature	150° F (65.5° C)		200° F (93.3° C)		250° F (121.1° C)		300° F (148.9° C)		350° F (176.6° C)	
Pressure, psi	0	2,000	2,000	4,000	4,000	6,000	6,000	8,000	8,000	10,000
600 rpm	44	50	34	38	28	31	25	27	21	22
300 rpm	32	36	25	27	21	22	17	18	14	15
200 rpm	26	28	20	21	16	17	13	14	10	11
100 rpm	20	22	15	17	12	13	10	11	8	9
6 rpm	10	10	7	8	6	7	5	5	4	4
3 rpm	9	9	7	7	5	6	4	5	3	3
Plastic viscosity, cP	12	14	9	11	7	9	8	9	7	7
Yield point, lb/100 ft^2	20	22	16	16	14	13	9	9	7	8
n	0.608	0.619	0.494	0.647	0.596	0.697	0.729	0.703	0.790	0.709
K, lb/100ft^2 sec^n	0.555	0.604	1.09	0.369	0.396	0.208	0.139	0.186	0.080	0.145
τ_0, lb/100 ft^2	7.8	7.6	1.5	6.4	4.3	5.9	4.08	3.70	3.27	3.07

Table 11-1: FANN 70 test results. This table contains data that illustrate the effects of temperature and pressure on the rheological properties of an oil-based mud.

High-angle sag test (HAST)

Description. The high-angle sag test (HAST), a static suspension-testing device, measures the sag potential of a fluid. A sample of drilling fluid is aged in the HAST

at a given angle and temperature to simulate the conditions in a deviated well. The change in the center of mass is measured every 10 minutes for 16 hours. The HAST can be run at temperatures up to 300°F (149°C) and at angles between 20 and 90 degrees.

Interpretation. The change in the center of mass is plotted in relation to time, and expressed as a sag coefficient. Drilling fluids with a sag coefficient lower than 10 have less tendency to sag in a deviated well (Figure 11-2).

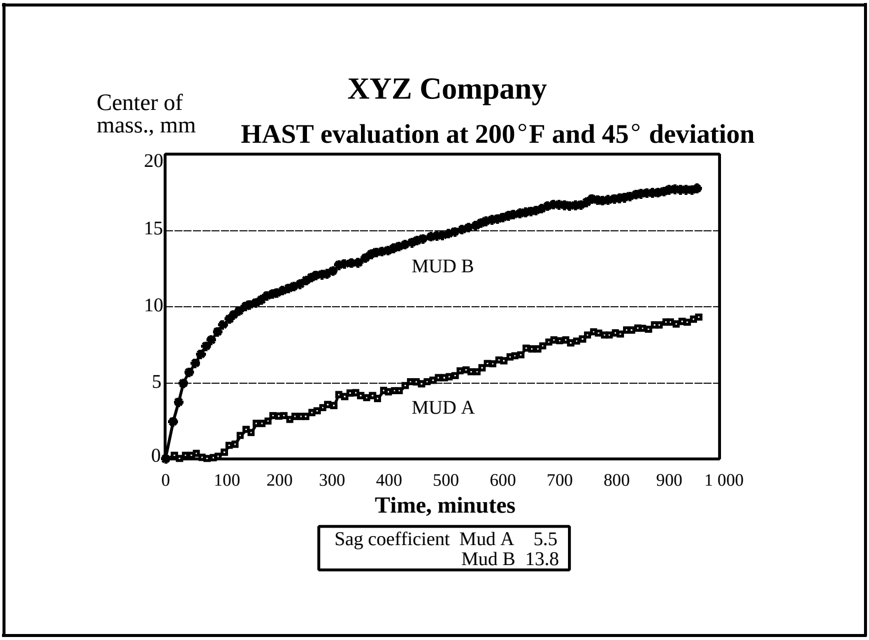

Figure 11-2: HAST results. This graph shows that Mud B has a greater tendency to sag in a deviated well.

Filtration tests

Filtration tests are used to determine the filtration properties of a drilling fluid.

- FANN 90 test
- Particle-plugging test (PPT)

FANN 90 test

Description. The FANN 90, a dynamic radial filtration apparatus, evaluates the filtration properties of a circulating fluid through a ceramic core. Dynamic filtration simulates the effect of fluid movement (shear rate) on the filtration rate and filter cake deposition. Normal operating conditions include:

- Temperatures up to 500°F (260°C)
- Core with mean pore throat diameters of 5 to 190 microns
- Differential pressure across the core up to 500 psi (3,447 kPa)

Interpretation. This test determines if the fluid is properly conditioned to drill through permeable formations. The test results include two numbers: dynamic filtration rate and cake deposition index (CDI; see Figure 11-3). The dynamic filtration rate is calculated from the slope of the curve of volume versus time. The CDI, which reflects the erodibility of the wall cake, is calculated from the slope of the curve of volume/time versus time. CDI and dynamic filtration rate are calculated using data collected after twenty minutes. Recommended maximum values for the dynamic filtration rate and the CDI are shown in Table 11-2.

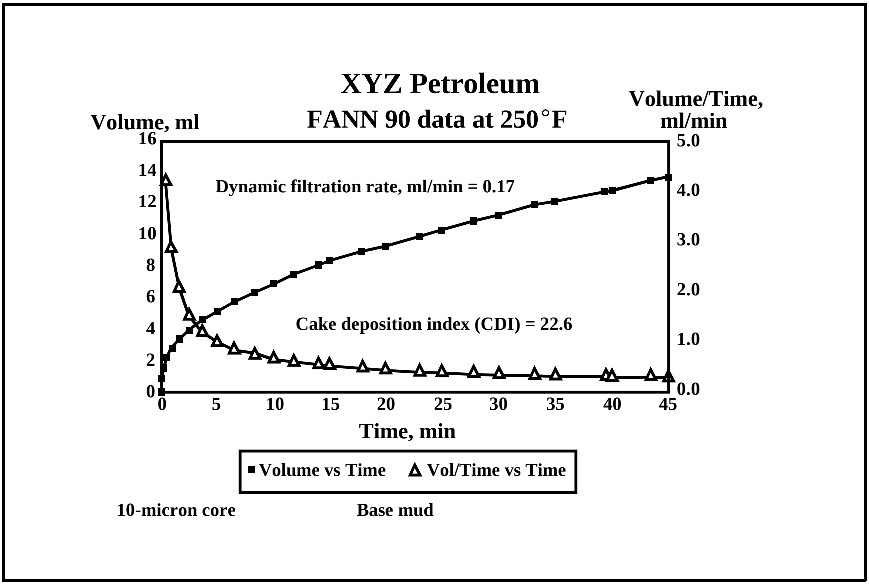

Figure 11-3: FANN 90 test results. This graph is typical of FANN 90 test results.

FANN 90 maximum recommended values		
Mud weight, lb/gal (sg)	**Rate, mL/min**	**CDI**
9–12 (1.08-1.44)	0.22	25
12–15 (1.44-1.80)	0.18	20
15 or greater (1.80 or greater)	0.14	16

Table 11-2: FANN 90 maximum recommended values. This table lists the recommended maximum values for the dynamic filtration rate and the CDI.

Particle-plugging test (PPT)

Description. The particle-plugging apparatus is a static inverted HTHP filter press with a ceramic disk as a filter medium. This static test measures the pore-plugging ability of a fluid. The PPT results include the

initial spurt loss and the total volume loss over 30 minutes.

Normal operating conditions include:

- Temperatures up to 350°F (176°C)
- Differential pressures up to 2,000 psi (13,770 kPa)
- Ceramic disk with mean pore-throat diameters of 5 to 190 microns

Aniline point test

Description. The aniline point test indicates the relative aromatic content of an oil. The aniline point is the lowest temperature at which equal volumes of aniline and oil are completely miscible.

Interpretation. An aniline point of 150°F (65°C) or higher indicates the oil is less likely to damage rubber components.

Particle-size distribution (PSD) test

Description. This analyzer uses laser diffraction technology to measure particle size distribution of the drilling fluid. Particle-size distribution (PSD) is determined using a Malvern particle-size analyzer.

Particle size distribution test results

Upper	In	Lower	Under	Upper	In	Lower	Under	Upper	In	Lower	Under
				36.3	5.6	31.4	78.0	6.18	2.9	5.33	20.1
				31.4	4.7	27.1	73.3	5.33	2.7	4.60	17.4
				27.1	5.2	23.3	68.1	4.60	2.4	3.97	15.0
				23.3	6.3	20.2	61.8	3.97	2.1	3.42	12.9
118	0.5	102	99.5	20.2	6.5	17.3	55.3	3.42	2.0	2.95	10.9
102	0.5	88.2	99.0	17.3	5.2	15.0	50.1	2.95	1.9	2.55	9.0
88.2	0.5	76.0	98.5	15.0	5.3	12.9	44.7	2.55	1.6	2.19	7.5
76.0	0.6	65.6	97.9	12.9	5.5	11.1	39.3	2.19	1.1	1.90	6.4
65.6	0.6	56.6	97.3	11.1	5.1	9.63	34.2	1.90	0.8	1.64	5.6
56.6	2.2	48.8	95.1	9.63	4.5	8.31	29.7	1.64	0.7	1.41	4.8
48.8	5.2	42.1	89.9	8.31	3.6	7.16	26.1	1.41	0.6	1.22	4.2
42.1	6.3	36.3	83.6	7.16	3.0	6.18	23.0	1.22	4.2	0.32	0.0

Source = :Sample Focal length = 63 mm Presentation = pil	Beam length=2.0 mm Log. Diff. = 1.382 Obscuration = 0.2891 Volume distribution	Model indp Volume Conc=0.0325% Sp.S.A .0499 m2/cc.

Span	2.63
D[4.3]	19.70 m
D[3.2]	5.72 m
D[v.0.9]	42.23 m
D[v.0.1]	2.76 m
D[v.0.5]	14.99 m

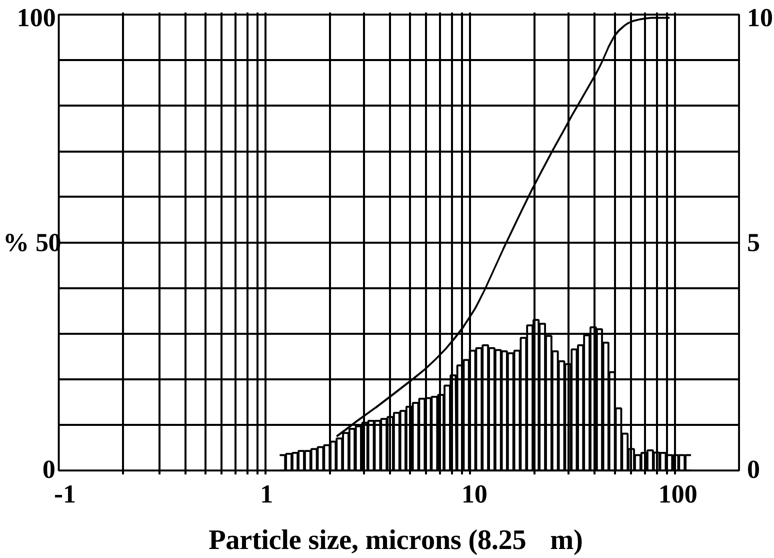

Figure 11-4: PSD test results. The D[v.0.5](d_{50}) rating at the lower right-hand corner of the table shows the median size of all solids in the fluid sample.

Interpretation. Precise particle-size distribution information is beneficial in evaluating the condition of a mud and the efficiency of the solids-control equipment. The test results are presented in a table and a graph, as in Figure 11-4. The table lists the amount of particles grouped by size (in microns). The graph shows the concentration (volume percent) of mud solids in a particular size range. One very useful number from the PSD test is the d_{50}, which is the median size of the solids in the mud sample.

Luminescence fingerprinting

Description. The hydrocarbon content of ester-based and oil-based systems can be estimated by luminescence fingerprinting.

Lubricity test

Description. The lubricity meter measures the coefficient of friction (Baroid lubricity coefficient) between the test ring and block. The lubricity test simulates drillpipe rotation against downhole surfaces. A constant load of 150 inch-pounds is applied using a torque arm.

Interpretation. The results of the lubricity test are expressed as a single value called the lubricity coefficient. The following coefficients are recognized as acceptable:

- For water-based mud, a coefficient < 0.2
- For oil-based mud, a coefficient < 0.1
- For ester-based mud, a coefficient < 0.1

Shale tests

Problems such as stuck pipe, tight hole, washout, and sloughing can be related to shale stability. Tests used to determine if a specific shale is likely to cause problems include the:

- Capillary suction time (CST) test
- Linear-swell meter (LSM) test
- Shale erosion test

Capillary suction time (CST) test

Description. The CST device measures the time it takes for a given amount of free water from a slurry to travel radially between two electrodes on thick, porous filter paper. The CST test measures the hydrating and dispersion properties of shales by simulating the shear and chemical forces present during drilling. For the CST test, the shale-solids content and mixing time are held constant, while the chemical characteristics such as pH and salinity are varied.

Interpretation. CST test results are graphed to show the CST value in time versus test fluid type.

The CST value is an indication of cake permeability. Highly dispersed particles give low cake permeability and high CST values. Flocculated particles give high cake permeability and low CST values. The CST value depends on solids type and content of the slurry, degree of mixing, pH, salinity, deflocculant or dispersant type and concentration, and polymer type and concentration.

CST test results show the inhibitive effects of various salts and their concentrations on the dispersion of a shale (Figure 11-5).

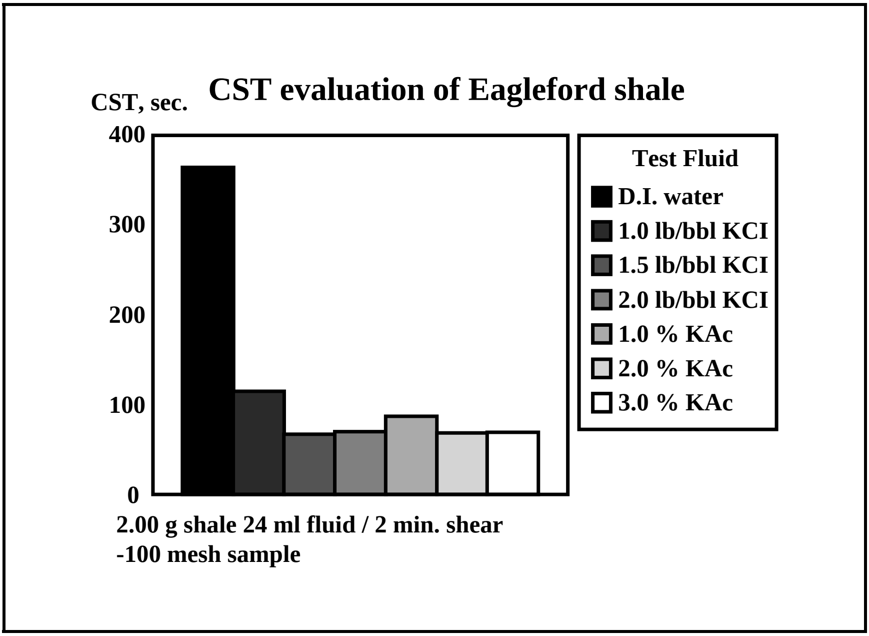

Figure 11-5: CST test results. These results show that both KCl and KAc are effective inhibitors for this particular shale.

Linear-swell meter (LSM) test

Description. The linear-swell meter apparatus is used to determine shale hydration or dehydration by measuring the increase or decrease in length over time of a reconstituted or intact shale core. The LSM test is used with the CST test to determine the recommended mud system for drilling through a specific shale formation. First, a CST test is conducted to determine the correct inhibitor for the shale. Then, a variety of muds are tested.

Interpretation. LSM test results are graphed to show the percent of swelling versus swelling time in minutes.

The LSM test results demonstrate the inhibitive effects of these various muds on shale swelling (Figure 11-6).

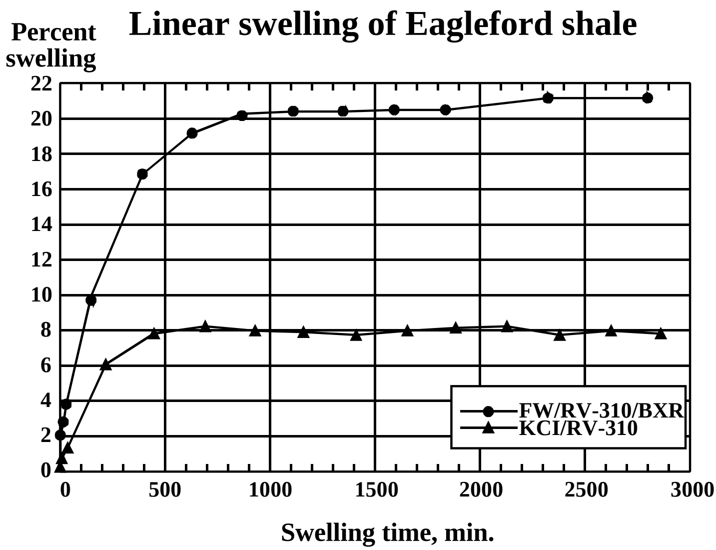

Figure 11-6: LSM test results. When compared with a freshwater RV-310/BXR mud, KCl/RV-310 provides better inhibition.

Shale erosion test

Description. The shale erosion test is used to measure the dispersive effect a mud will have on a specific type of shale. A shale sample is screened to obtain particles that pass through a 6-mesh screen, but stay on an 12-mesh screen. Equal weights of the shale are put into test muds. The test muds are then hot rolled at 150°F (65°C) for 16 hours and screened through a 12-mesh screen. The solids retained on the 12-mesh screen are washed, dried, and weighed. The initial moisture content is taken into account when calculating percent erosion.

Interpretation. Test results are provided in percent erosion. The percent erosion is calculated based on the measured weight loss after the sample has been rolled for 16 hours at 150°F (65°C).

	KCl/RV-310	KCl/CAT-I	Fresh water/Q-BROXIN
% Erosion	4.4	2.5	15.3

Table 11-3: Shale erosion test results. A percent erosion of less than 5 percent indicates the shale does not erode in the fluid tested.

Return permeability test

Description. The return permeability test is used to measure the effect of a test fluid (whole mud, mud filtrate, or brine) on the permeability of a producing formation. The test uses plugs cut from a core sample. After baseline permeability (K_I) is measured, the plug is exposed to the test fluid. Permeability is measured again (K_f) after exposure to the test fluid and a percent return is calculated (K_f / K_I × 100). 100 percent return indicates no formation damage.

To perform the test, the lab requires the following:

- Core sample
- Density requirements
- Formation pressure or expected overbalance pressure
- Type of production
- Formation water analysis
- Any other available well history or information for the region

Interpretation. Return permeability data are usually shown as a graph of permeability versus flow. Figure 11-7 shows the percent return of permeability.

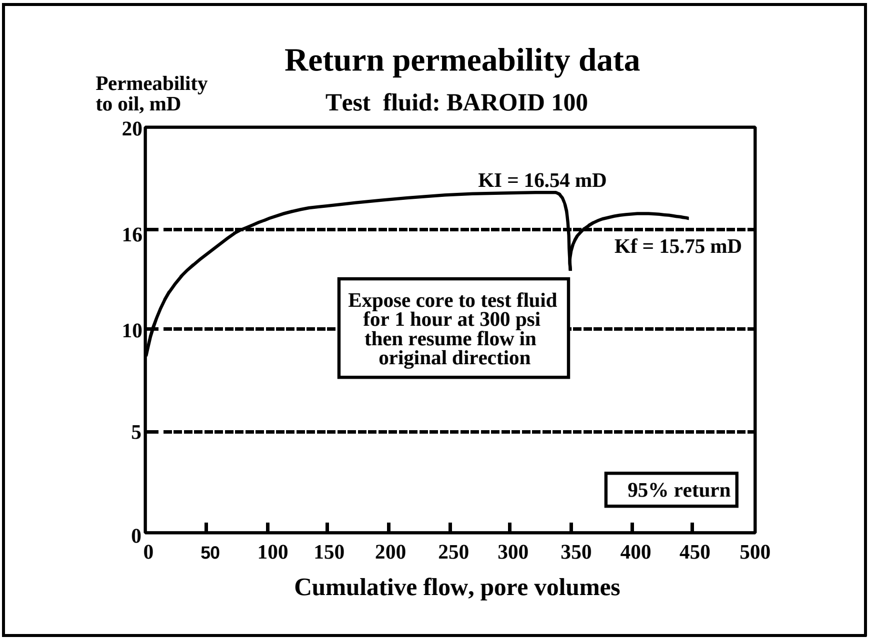

Figure 11-7: Return permeability test results. BAROID 100 fluid had a return permeability rating of 95 percent in this test.

Bacteria test

Description. A phenol-red serum test (aerobic bacteria) or a marine anaerobic serum test (anaerobic bacteria) can be used to determine the concentration of bacteria in drilling fluid, makeup water, or reserve pit water. The test is performed using seven bottles with successive ten to one dilutions of the sample fluid. These are observed over a 7-day test interval. The number of bottles that change color and the number of days in which the change occurs are an indication of the bacterial concentration in the samples.

Interpretation. Results are reported in bacteria per milliliter of fluid used for the test. A test in which four bottles give a positive indication over a 72-hour test interval (100,000 to 999,999 bacteria/mL) indicates a problem. When seven bottles give a positive indication (1,000,000 to 9,999,999 bacteria/mL), regardless of the time over which the change occurs, there is serious bacterial contamination.

Brine and formation water compatibility test

Description. The compatibility test can be used to evaluate whether a proposed completion brine will react with the formation water and damage the formation. A sample of the formation water or synthetic formation water is blended with the desired brine and then hot rolled at the reservoir temperature. The brine and formation water are blended at various ratios to determine the maximum contamination the brine can tolerate before a precipitate is formed.

Interpretation. If a precipitate is formed during the blending or after hot rolling, the two aqueous media are considered incompatible. The brine formation is altered until an unreactive pair is identified.

X-ray diffraction test

Description. X-ray diffraction analysis can be used to determine the mineralogy of cuttings and cores from a relatively small sample. Finely ground samples are bombarded by x-rays, and the resulting reflections are measured. This provides a semi-quantitative analysis of the mineral constituents of the sample.

Interpretation. Test results can be used to evaluate the reactivity of a formation, especially a clay-type formation. Test results are usually presented in weight percent and dictate the degree of inhibition required for borehole stability. Common clay types include smectite, kaolinite, illite, and chlorite.

CHAPTER

12

Stuck pipe

The Complete Fluids Company

Contents

Overview

In drilling operations, the drillpipe is considered stuck when it cannot be raised, lowered, or rotated. Stuck pipe can be caused by several different mechanisms. Typical stuck pipe situations are:

- Differential-pressure effects
- Packing off
- Undergauge hole
- Keyseating

Differential sticking

Most incidents of stuck pipe are caused by differential-pressure effects. Excessive differential pressures across lower-pressure permeable zones can cause the drillstring to push into the wellbore wall where it becomes stuck. See Figure 12-1.

Differential sticking may be identified by the following characteristics:

- Pipe sticks after remaining motionless for a period of time
- Pipe cannot be rotated or moved when circulation is maintained

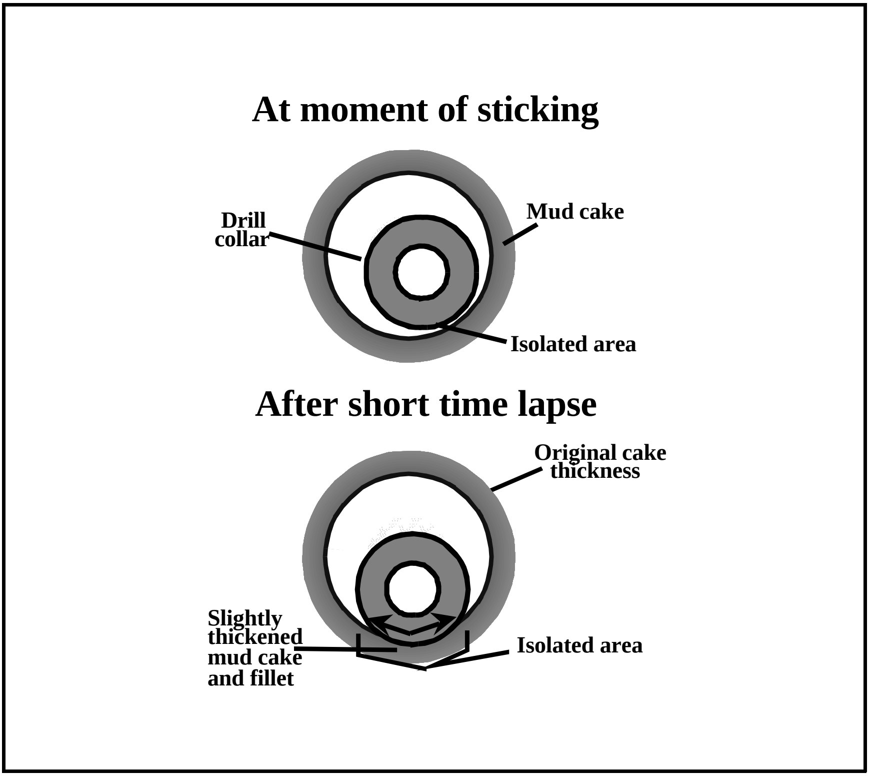

Figure 12-1: Differential-pressure effect. The difference in pressure between the hydrostatic head pressure and the formation pore pressure forces the drillpipe into the wallcake and sticks the pipe.

To avoid or minimize the risk of differential sticking, follow these guidelines:

- Drill with the lowest practical mud weight.
- Maintain a low filtration rate.
- Keep low-gravity solids to a minimum.
- Never allow the drillpipe to remain motionless for any period of time.
- Ream any undergauge section.
- Add appropriate bridging agents.
- Change to an oil/synthetic-based mud.

ENVIRO-SPOT spotting fluid

When differential sticking occurs, spotting fluid can sometimes free the drillpipe.

Note: It is critical to have a spotting fluid readily available and apply it within six hours of the stuck pipe occurrence.

Spotting fluids are designed to penetrate and break up the filter cake. To mix the ENVIRO-SPOT spotting fluid, start with the required volume of oil and add ENVIRO-SPOT, water, and BAROID in that order.

Base fluids can be diesel, mineral oil, water, etc. See Table 12-1.

ENVIRO-SPOT spotting fluid formulation for 100 bbl						
Weight, lb/gal (sg)	**7.3 (0.87)**	**10.0 (1.20)**	**12.0 (1.44)**	**14.0 (1.68)**	**16.0 (1.92)**	**18.0 (2.16)**
Oil, bbl (m^3)	64 (10.3)	58 (9.2)	54 (8.6)	49 (7.8)	51 (8.1)	44 (7.0)
ENVIRO-SPOT, 55 gal drum	6 (.98)	6 (.98)	6 (.98)	6 (.98)	6 (.98)	6 (.98)
Water, bbl (m^3)	28 (4.5)	26 (4.1)	22 (3.5)	21 (3.3)	11 (1.7)	10 (1.6)
BAROID, lb (kg)	n/a	14,000 (6,350)	25,000 (11,340)	35,000 (15,876)	46,500 (21,092)	57,000 (25,855)

Table 12-1: ENVIRO-SPOT formulation. ENVIRO-SPOT is a good all-purpose spotting fluid suitable for use in many different drilling regions.

DUAL PHASE spotting fluid

Density

Make the spotting fluid density equal to the mud weight in use. PHASE ONE has a starting density of 14.2 lb/gal (1.70 sg) and can be increased with calcium chloride to as high as 15.1 lb/gal (1.81 sg). PHASE ONE can be reduced with seawater/drill water to the desired density. PHASE TWO has a starting density of 8.6 lb/gal (1.03 sg). Adjust the density of PHASE TWO, as needed, by additions of weight material.

Volumes Needed

PHASE ONE - 50 bbl minimum

PHASE TWO - 100 bbl minimum

Note: Larger volumes may be required to ensure that the stuck point is covered by the spotting fluid.

Displacement

1. PHASE ONE should be mixed in the slugging pit. Adjust the weight to the drilling fluid density. Pump PHASE ONE into the drill string at the normal pump rates.
2. PHASE TWO should be mixed in the slugging pit. Adjust the weight to the drilling fluid density. Pump PHASE TWO into the drill string at the normal pump rates.
3. Pump the PHASE ONE through the bit leaving 10 barrels of PHASE ONE inside the drill string (If the drill string capacity is greater than the volumes of both PHASE ONE and PHASE TWO pills), mud should be pumped to complete the spotting procedure.12-4

Soak Time

1. Break circulation once per hour pumping one barrel of fluid. PHASE ONE should have a minimum soak/exposure time of nine (9) hours.
2. After nine hours of soak time, pump PHASE TWO into the annulus at a slow pump rate. Leave 15 barrels of PHASE TWO inside the drill string.
3. Break circulation every hour pumping one barrel of fluid.
4. When the pipe becomes free, pump all of the DUAL PHASE out of the hole and discard the DUAL PHASE and interface.
5. Once the DUAL PHASE has been discarded, the mud should be conditioned with deflocculating and fluid loss control additives.

DUAL PHASE WORKSHEET					
Date	________________		**Pipe**	**OD ID Capacity/ft**	
Operator	________________		DC	____________________	
Offshore Area	________________		HWDp	____________________	
Block	________________		Dp 1	____________________	
Last Casing Shoe	______	MD/ft	Dp 2	____________________	
Total Depth	______	MD/ft	Dp 3	____________________	
Bit Location	______	MD/ft	______________________________		
Bit Size	______	inches	**Hole Data**		
BHA Length	______	feet	Annular Vol. DC/OH	____bbl	
Drill Collar Length	______	feet	Annular Vol. HW/OH	____bbl	
HW Pipe Length	______	feet	Annular Vol. Dp 1	____bbl	
Drill Pipe Length	______	feet	Annular Vol. Dp 2	____bbl	
Drill Pipe Length	______	feet	Annular Vol. Dp 3	____bbl	
Drill Pipe Length	______	feet	Annular Vol. Dp 4	____bbl	
Total String Length	______	**feet**	Annular Vol. bit-shoe	____bbl	
Pump Data			PHASE ONE Volume		
Pump	______	bbl/stroke			
Stroke to bit	______	strokes	Feet of coverage DC/OH	____ bbl	
			Feet of coverage HW/OH	____ bbl	
Placing ***PHASE ONE & TWO***			Feet of coverage Dp/OH	____ bbl	
	Vol.	**Strokes to Spot**	Feet of coverage Dp/OH	____ bbl	
***PHASE ONE*____**	**bbl**	______	Feet of coverage Dp/OH	____ bbl	
***PHASE TWO* ____**	**bbl**	______	Footage Covered - *PHASE ONE*	____ bbl	

Table 12-2: DUAL PHASE worksheet. This worksheet can be used to calculate the volumes required to be pumped and a pump schedule.

PHASE ONE 50 bbl			
Desired Density, lb/gal	PHASE ONE bbl	$CaCl_2$ 80 lb Sacks	Water bbl
15.1	43	79	
15.0	43	71	
14.9	44	62	
14.8	45	54	
Note: At 14.8-15.1 lb/gal-TCT is 63° F			
14.7	46	43	
14.6	47	32	
14.5	48	24	
14.4	49	15	
14.3	49	9	
14.2	**50**		**0.0**
14.0	48		2
13.5	44		6
13.0	40		10
12.5	35		15
12.0	31		19
11.5	27		23
11.0	22		28
10.5	18		32
10.0	14		36
9.5	10		41
9.0	5		44

PHASE TWO 100 bbl			
Desired Density, lb/gal	PHASE TWO bbl	Water bbl	Barite sacks
15.5	53	20	332
15.0	53	22	370
14.3	58	20	332
14.2	56	22	325
14.0	57	22	315
13.5	65	15	300
13.0	68	15	255
12.5	73	12	222
12.0	75	12	193
11.0	80	10	147
10.5	82	10	120
10.0	83	10	100
9.5	95	0	74
9.2	98	0	35
8.6	100	0	0

Table 12-3: DUAL PHASE density table. This table can be used to calculate the required amounts of materials to achieve the desired density.

Determining depth to stuck zone

Measure the drillstring stretch to estimate the depth that pipe is stuck. The following formula locates the depth at which the pipe is stuck. The length of free pipe is based on the drillstring dimensions and the measured amount of stretch.

$$L = \frac{E\,e\,W}{40.8\;P}$$

Where

- *L* is the length of free pipe (ft)
- *E* is the modulus of elasticity (30×10^6) (psi)
- *e* is the stretch (in)
- *W* is the weight of pipe (per ft)
- *P* is the amount of tension applied (lb/ft)

Packing off

Drilling-fluid systems with poor suspension characteristics exhibit strong packing-off tendencies (see Figure 12-2). Factors that can lead to caving of the formation include:

- Pressure imbalance
- Shale hydration
- Bottomhole assembly striking the wall

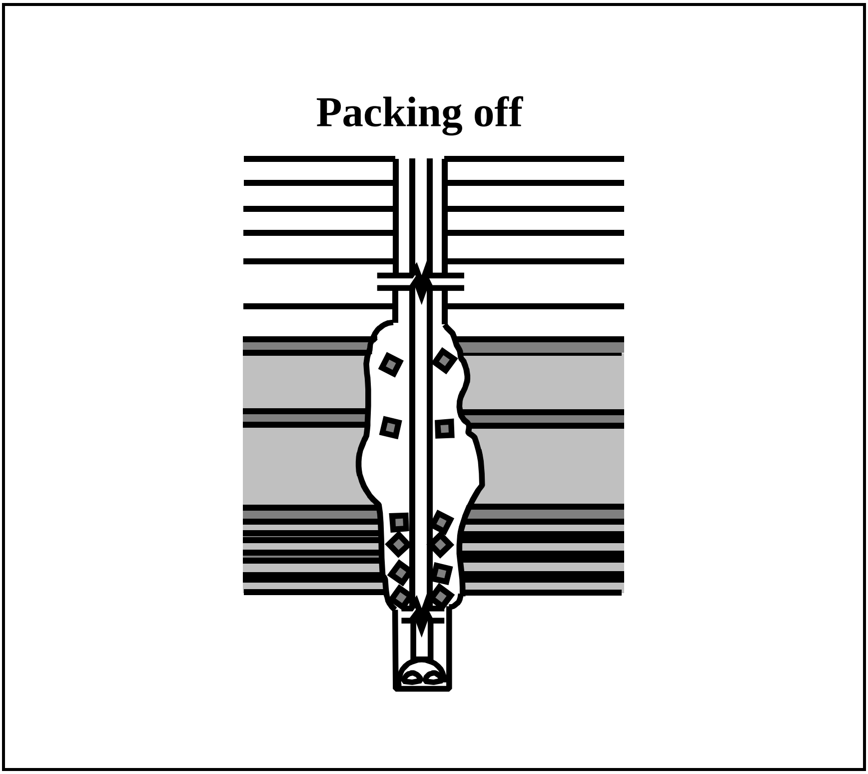

Figure 12-2: Packing off. Massive particle caving sticks the drillbit.

Undergauge hole

Undergauge hole is a condition where the borehole is smaller than the bit diameter used to drill the section. Undergauge hole can result from any of the following causes:

- Plastic flowing formations
- Wall-cake buildup in a permeable formation
- Swelling shales

Plastic flowing formations

A plastic flowing formation is a formation that is plastic (easily deformable when stressed) and can flow into the borehole. When these types of formations are penetrated by the bit, the hole is at gauge. However, when the hydrostatic pressure exerted by the column of drilling fluid is less than the hydrostatic pressure of the formation, underbalance results, the formation flows, and hole diameter decreases.

Undergauge hole is a common problem when drilling a thick salt section with an oil mud. The salt can flow into the borehole and make the section undergauge. When plastic salt formations exist, they are usually below 5,000 feet. Spotting fresh water is the best way to free the pipe from a plastic salt formation.

Wall-cake buildup

Wall-cake buildup occurs when the drilling fluid has poor filtration control across a permeable zone. Excessive wall-cake buildup can also be caused by:

- High percentage of low-gravity solids
- High differential pressures (excessive mud weights)

Keyseating

Keyseating is a situation frequently encountered in deviated or crooked holes when the drillpipe wears into the wall. The normal drilling rotation of the drillstring cuts into the formation wall in deviated areas where the drillpipe tension creates pressure against the sides of the hole.

Keyseating is diagnosed when the drillpipe can be reciprocated within the range of tool joint distances or until collar reaches the keyseat, while pipe rotation and circulation remain normal. See Figure 12-3 for an example of a keyseat effect in a crooked hole.

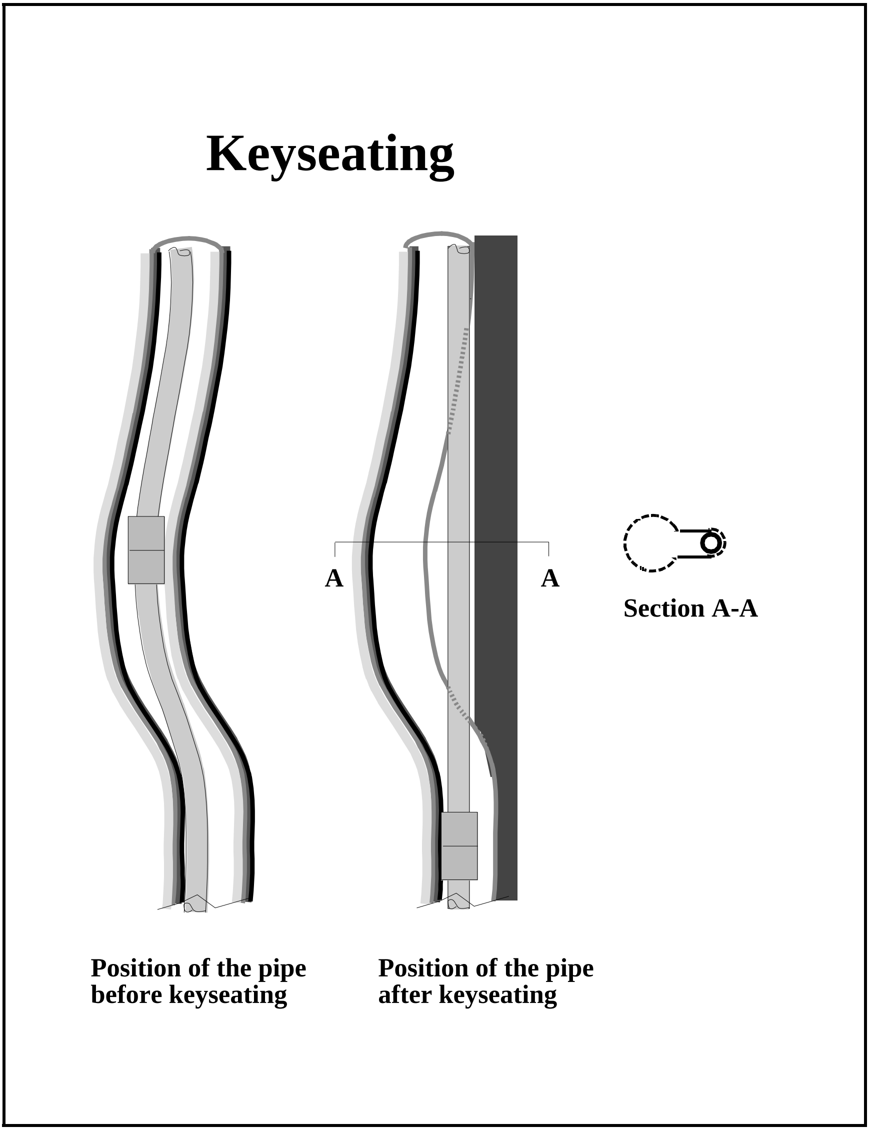

Figure 12-3: Keyseating. The friction generated by drillpipe rotation against the borewall cuts a narrow channel, or keyseat, into the formation.

A preventive measure is to carefully control upper hole deviation and dogleg severity throughout the well path. This action will eliminate the force that leads to keyseat creation.

Once a keyseat is formed, the best solution is to ream out the small-diameter portions of the hole with reaming tools. See the example of reaming action in Figure 12-4. This action will solve the immediate stuck-pipe problem, but the keyseat can be formed again unless preventive steps are taken.

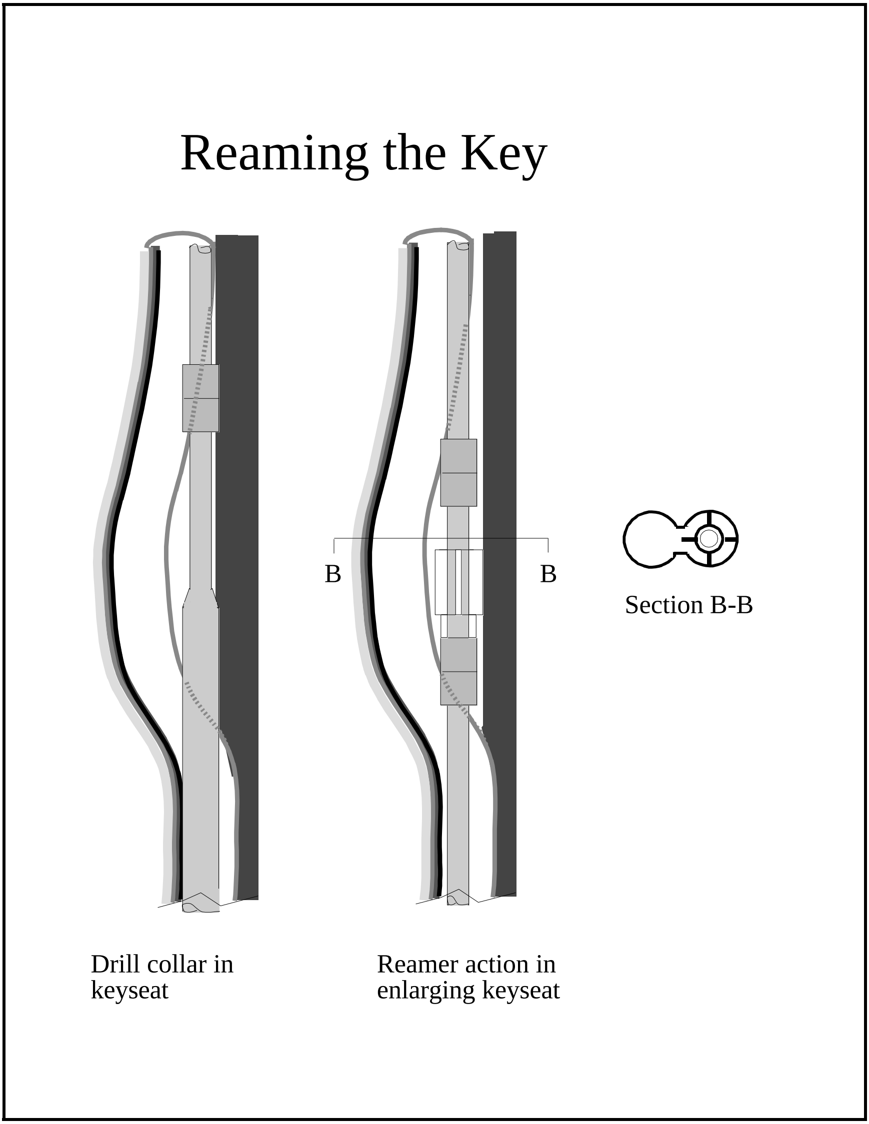

Figure 12-4: Reaming action. Attach a reamer to the drill assembly to widen the keyseat.

Freeing stuck pipe

The following guidelines can be used to free stuck pipe:

Cause...	Steps to free...
Differential sticking	Reduce mud weight. Use spotting fluid.
Packing off	Back off and wash over.
Undergauge hole	Increase mud weight. Underream.
Keyseating	Ream the keyseat.

CHAPTER **13**

Synthetics

The Complete Fluids Company

Contents

PETROFREE Overview

PETROFREE systems are formulated with a vegetable-based ester as the continuous or external phase. PETROFREE systems are recommended for drilling in environmentally sensitive areas worldwide. The properties of PETROFREE systems are influenced by:

- Ester/water ratio
- Emulsifier concentration
- Solids content
- Downhole temperature and pressure

Note: PETROFREE muds can be formulated for stability at temperatures approaching 300°F (149°C).

PETROFREE systems

PETROFREE systems are classified in two categories: PETROFREE and PETROFREE 100. Table 13-1 outlines the primary uses of these two systems.

System	Application
PETROFREE	For deepwater, high-angle, extended-reach applications
PETROFREE 100	For use as a nondamaging coring and drilling fluid

Table 13-1: PETROFREE systems. Each PETROFREE system was developed to meet specific drilling requirements.

PETROFREE

PETROFREE systems use emulsifiers and fluid-loss agents that provide maximum emulsion stability and minimal filtrate loss. Table 13-2 provides guidelines for formulating PETROFREE systems.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3) to 300°F (149°C)
Ester	Continuous phase	As needed
EZ MUL NTE	Emulsifying agent	8-16 (23-46)
Lime	Alkalinity source	0-2 (0-6)
DURATONE HT	Fluid-loss control agent	8-14 (23-40)
Water	Discontinuous phase	As needed
GELTONE II/ V	Viscosifier	0.5-2 (1.4-6)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed
$CaCl_2$	Salinity source	As needed

Table 13-2: PETROFREE system formulation guidelines. The base fluid of a PETROFREE system is a vegetable-based ester.

PETROFREE 100

PETROFREE 100 all-ester systems are used when maintaining the native state of the geologic formation is a primary concern. These systems are not used where water contamination is a known problem. Table 13-3 provides guidelines for formulating PETROFREE 100 systems.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Ester	Continuous phase	As needed
EZ-CORE	Passive emulsifier	3 (9)
* EZ MUL NTE	Emulsifier	0-6 (0-17)
BARABLOK or BARABLOK 400 or DURATONE HT	Filtration control agent	5-15 (14-43)
GELTONE II/V	Viscosifier	6-14 (17-40)
BARACTIVE	Polar additive	2-6 (6-17)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed
Lime	Alkalinity source	0-0.5 (0-1.4)

Table 13-3: PETROFREE 100 system formulation guidelines. The base fluid of a PETROFREE 100 system is a vegetable-based ester.

* EZ MUL NTE may be added when a large amount of water contamination occurs.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

Mud management

When maintaining a PETROFREE system:

- Do not run excess lime > 0.5 lb/bbl (1.4 kg/m^3).
- Do not use cellulosic LCM.
- Do not add weighting agents when adding water.
- Maintain an all-ester HTHP filtrate.
- Use solids-control equipment to prevent buildup of low-gravity solids.
- Add EZ MUL NTE slowly as weighting agents are added to help oil-wet the additional solids.

Note: Only EZ MUL NTE should be added to the PETROFREE systems. The use of other emulsifiers will introduce petroleum hydrocarbon contamination.

- Do not saturate the water phase with $CaCl_2$ because emulsion instability and water-wetting of solids can occur.
- Do not add any materials that contain petroleum hydrocarbons.
- Use OMC 42 when a thinner is required.

Note: When the product concentration of OMC 42 reaches 4 lb/bbl (11 kg/m^3), use OMC 2 in small amounts (0.25 to 0.5 lb/bbl [0.7 to 1.4 kg/m^3]) for supplemental thinning.

- Maintain ester/water ratios within the recommended range. Table 13-4 lists typical ester/water ratios.

Mud density, lb/gal (sg)	Recommended ester/water ratio
9-11 (1.08-1.32)	70/30 - 80/20
11-13 (1.32-1.56)	75/25 - 85/15
13-15 (1.56-1.80)	85/15 - 90/10
15-16 (1.80-1.92)	85/15 - 90/10
16-17 (1.92-2.04)	90/10 - 95/5
17-18 (2.04-2.16)	95/5 - 100/0

Table 13-4: Ester/water ratios. This table lists the lowest and highest ester/water ratios for given mud density.

Logging

PETROFREE systems do not conduct electric current; therefore, do not use logging tools that require electric conductance to measure resistivity. Table 13-5 provides guidelines for logging in PETROFREE systems.

Objective	Tool	Notes
Depth control correlation and lithology	Induction/gamma ray log Formation density log Sonic log Neutron log Dipmeter	Use the gamma ray log to determine sand and shale sequences. Use the other logs for identifying complex lithology.
Percent shale in shaley sands	Gamma ray log	The gamma ray log method replaces the sand/shale index found in fresh waters from the SP log.
Net sand (sand count)	Formation density log Gamma ray log Resistivity log	Use the formation density log, a resistivity log, and/or the caliper log to determine sand count because the sand and shale densities differ.
Detect hydrocarbon-bearing formations	Induction/gamma ray log Sonic log Neutron log	High resistivity values indicate hydrocarbon pore saturation. Use a formation density log in conjunction with neutron and sonic logs to identify hydrocarbons.
Interpretation • Water saturation	Induction, sonic, density, and neutron logs	Use Archie's equation to compute water saturation.
• Porosity	Formation density, sonic, and neutron logs; sidewall cores	
• Permeability	Sidewall cores	
• Structural formation	Continuous dipmeter	
• Productivity	Formation tester	

Table 13-5: Logging guidelines. A variety of logs are available to help determine downhole conditions.

Special application

PETROFREE thermal insulation systems

Thermal insulation systems are placed inside the casing in the annular space between the casing and the production tubing to minimize heat transfer and to prevent corrosion. As a result of minimal heat transfer, wax formation is reduced during the production process. Table 13-6 provides guidelines for formulating PETROFREE thermal insulation systems.

Additive	Application	Typical concentrations, lb/bbl (kg/m^3)
PETROFREE ester	Base fluid	As required
GELTONE II/V	Viscosifier	20 (57)
BARACTIVE	Polar additive	0.1-0.4 (0.3-1.1)

Table 13-6: PETROFREE thermal insulation system formulation guidelines. The base fluid of thermal-insulation systems is PETROFREE ester.

Product information

Viscosifiers/ suspending agents

Use organophilic clays to increase the rheological properties of PETROFREE systems. Use ester-dispersible polymeric fatty acids to enhance the low shear-rate viscosities of ester-based systems. Viscosifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
GELTONE II/V	Develops viscosity and suspension properties; requires a polar additive (like water) to develop maximum yield	Organophilic clay	1-12 (3-34)
RM-63	Enhances low-shear rheological properties	Polymeric fatty acid	0.1-1 (0.3-3)
SUSPENTONE	Provides suspension and minimize sag with minimal viscosity build-up	Organophilic clay	1-6 (3-17)

Table 13-7: Viscosifying products. A variety of products are available to increase rheological properties or enhance low shear-rate viscosities of ester-based muds.

Thinners

To thin PETROFREE systems, add base fluid to the system or treat with a variety of ester-soluble polycarboxylic acid or polymeric fatty acid derivatives.

Thinning products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
OMC 2	Reduces viscosity	Oligomeric fatty acid	0.25-1.5 (0.7-4)
OMC 42	Reduces viscosity	Polymer imide surfactant	0.5-4 (1.4-11)

Table 13-8: Thinning products. Thinning products are used to make PETROFREE systems less viscous.

Emulsifiers

Use emulsifiers to increase the stability of the emulsion of PETROFREE and reduce the water-wetting tendency of insoluble solids. Emulsifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
EZ-CORE	Acts as a passive emulsifier in the PETROFREE 100 systems	Refined tall oil fatty acid	2 (6)
EZ MUL NTE	Acts as the primary emulsifier in PETROFREE systems	Polyaminated fatty acid	8-15 (23-43)

Table 13-9: Emulsifying products. Emulsifiers increase emulsion stability and reduce the tendency of insoluble solids to water-wet.

Filtration control agents

To provide filtration control, add organophilic lignite or various asphaltic materials. Filtration control products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
DURATONE HT	Controls fluid loss at elevated temperatures; provides high-temperature stability (300°F [149°C]) *Note: When used with 100% ester systems, BARACTIVE polar activator is required to activate DURATONE HT.*	Organophilic leonardite	1-25
AK-70	Controls fluid loss at temperatures up to 275°F (135°C)	Blend of air-blown asphalt and clay with anti-caking agent	1-25 (3-71)
BARABLOK	Controls fluid loss at temperatures up to 300°F (149°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)

Table 13-10: Filtration control products. These products provide filtration control in PETROFREE systems.

PETROFREE LE Overview

PETROFREE LE systems are formulated using a blend of PETROFREE ester and a fluid derived from natural gas (LE BASE) as the continuous phase. PETROFREE LE systems are recommended for drilling in environmentally sensitive areas worldwide. The unique ability to select LE BASE/ ester ratios of the continuous phase permits the user to customize properties for enhanced lubricity and cuttings transport. PETROFREE LE systems are influenced by:

- LE BASE/Ester ratio
- Synthetic/water ratio
- Emulsifier concentration
- Solids content
- Downhole temperature and pressure

Note: PETROFREE LE muds can be formulated for stability at temperatures in excess of 400°F (205°C).

PETROFREE LE systems

PETROFREE LE systems are classified in two categories: PETROFREE LE and PETROFREE LE 100. Table 9-13 outlines the primary uses of these two systems.

System	Application
PETROFREE LE	For deepwater, high-angle, high density, high temperature and extended-reach applications
PETROFREE LE 100	For use as a nondamaging drilling fluid

Table 13-11: PETROFREE LE systems. Each PETROFREE LE system was developed to meet specific drilling requirements.

PETROFREE LE

PETROFREE LE systems use emulsifiers and fluid-loss agents that provide maximum emulsion stability and minimal filtrate loss. Table 13-12 provides guidelines for formulating PETROFREE LE systems.

Additive	**Function**	**Typical concentrations, lb/bbl (kg/m^3) to 325°F (163°C)**
LE BASE/Ester	Continuous phase	As needed
LE MUL	Primary emulsifier	0-8 (0-23)
LE SUPERMUL	Secondary emulsifier	5-12 (14-34)
Lime	Alkalinity source	2-3 (6-9)
$CaCl_2$	Salinity source	As needed
DURATONE HT	Fluid-loss control agent	5-12 (14-34)
Water	Discontinuous phase	As needed
GELTONE II/V	Viscosifier	4 - 6 (11-17)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed

Table 13-12: PETROFREE LE system formulation guidelines. This table lists typical product concentrations for PETROFREE LE systems with a stability up to 325°F (163°C).

PETROFREE LE 100

PETROFREE LE 100 all-synthetic systems are used when maintaining the native state of the geologic formation is a primary concern. These systems are not used where water contamination is a known problem. Table 13-13 provides guidelines for formulating PETROFREE LE 100 systems.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3) to 325°F (163°C)
LE BASE/Ester	Continous phase	As needed
EZ-CORE	Passive emulsifier	2 (6)
* LE SUPERMUL	Emulsifier	0-6 (0-17)
BARABLOK or BARABLOK 400 or DURATONE HT	Filtration control agent	5-15 (14-43)
GELTONE II/V	Viscosifier	6-14 (17-40)
BARACTIVE	Polar additive	2-6 (6-17)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed
Lime	Alkalinity source	1-3 (3-9)

Table 13-13: PETROFREE LE 100 system formulation guidelines. This table lists typical product concentrations for PETROFREE LE 100 systems with a stability up to 325°F (163°C).

* LE SUPERMUL may be added when larger than expected water contaminations occur.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

Mud management

When maintaining a PETROFREE LE system:

- Do not use cellulosic LCM.
- Do not add weighting agents when adding water.
- Maintain an all-"synthetic" HTHP filtrate.
- Use solids-control equipment to prevent buildup of low-gravity solids.
- Add LE SUPERMUL slowly as weighting agents are added to help oil-wet the additional solids.

Note: Only LE SUPERMUL, LE MUL , or EZ CORE (100% synthetic systems) should be added to the PETROFREE LE systems. The use of other emulsifiers will introduce petroleum hydrocarbon contamination.

- Do not saturate the water phase with $CaCl_2$ because emulsion instability and water-wetting of solids can occur.
- LE MUL is recommended when mud weights exceed 14.0 lb/gal (1.68 sg).
- Do not add any materials that contain petroleum hydrocarbons.
- Use LE THIN when a thinner is required.

Note: When the product concentration of LE THIN reaches 4 lb/bbl (11 kg/m^3), use OMC 2 in small amounts (0.25 to 0.5 lb/bbl [0.7 to 1.4 kg/m^3]) for supplemental thinning.

- Maintain synthetic/water ratios within the recommended range. See table 13-14.

Mud density, lb/gal (sg)	Recommended synthetic/water ratio
9-11 (1.08-1.32)	60/40 - 70/30
11-13 (1.32-1.56)	70/30 - 80/20
13-15 (1.56-1.80)	80/20
15-16 (1.80-1.92)	85/15
16-17 (1.92-2.04)	85/15 - 90/10
17-18 (2.04-2.16)	90/10 - 95/5

Table 13-14: Synthetic/water ratios. This table lists the recommended synthetic/water ratios for given mud densities.

Logging

PETROFREE LE systems do not conduct electric current; therefore, do not use logging tools that

require electric conductance to measure resistivity. Table 13-15 provides guidelines for logging in PETROFREE LE systems.

Objective	**Tool**	**Notes**
Depth control correlation and lithology	Induction/gamma ray log Formation density log Sonic log Neutron log Dipmeter	Use the gamma ray log to determine sand and shale sequences. Use the other logs for identifying complex lithology.
Percent shale in shaley sands	Gamma ray log	The gamma ray log method replaces the sand/shale index found in fresh waters from the SP log.
Net sand (sand count*)*	Formation density log Gamma ray log Resistivity log	Use the formation density log, a resistivity log, and/or the caliper log to determine sand count because the sand and shale densities differ.
Detect hydrocarbon-bearing formations	Induction/gamma ray log Sonic log Neutron log	High resistivity values indicate hydrocarbon pore saturation. Use a formation density log in conjunction with neutron and sonic logs to identify hydrocarbons.
Interpretation • Water saturation • Porosity • Permeability • Structural formation • Productivity	Induction, sonic, density, and neutron logs Formation density, sonic, and neutron logs; sidewall cores Sidewall cores Continuous dipmeter Formation tester	Use Archie's equation to compute water saturation.

Table 13-15: Logging guidelines. A variety of logs are available to help determine downhole conditions.

Product Information

Viscosifiers/ suspending agents

Use organophilic clays to increase the rheological properties of PETROFREE LE systems. Use ester-dispersible polymeric fatty acids to enhance the low shear-rate viscosities of ester-based systems. Viscosifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
GELTONE II/V	Develops viscosity and suspension properties; requires a polar additive (like water) to develop maximum yield; maximum yield achieved with minimal shear	Organophilic clay	1-12 (3-34)
RM-63	Enhances low-shear rheological properties	Polymeric fatty acid	0.5-1.5 (1.4-4)
SUSPENTONE	Provides suspension and minimize sag with minimal viscosity build-up	Organophilic clay	1-6 (3-17)

Table 13-16: Viscosifying products. A variety of products are available to increase rheological properties or enhance low shear-rate viscosities of PETROFREE LE.

Thinners

To thin PETROFREE LE systems, add base fluid to the system or treat with polycarboxylic acid or polymeric fatty acid derivatives. Thinning products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
OMC 2	Reduces viscosity	Oligomeric fatty acid	0.25-1.5 (0.7-4)
LE THIN	Reduces viscosity	Polyimide surfactant	0.5-4 (1.4-11)

Table 13-17: Thinning products. Thinning products are used to make PETROFREE LE systems less viscous.

Emulsifiers

Use emulsifiers to increase the stability of the emulsion of PETROFREE LE and reduce the water-wetting tendency of insoluble solids. Emulsifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
EZ-CORE	Acts as a passive emulsifier in the PETROFREE LE 100 systems	Refined tall oil fatty acid	2 (6)
LE MUL	Primary emulsifier	Blend of oxidized tall oil and polyaminated fatty acid	0-8 (0-23)
LE SUPERMUL	Acts as the secondary emulsifier in PETROFREE LE systems	Partial amide of a fatty acid	8-15 (23-43)

Table 13-18: Emulsifying products. Emulsifiers increase emulsion stability and reduce the tendency of insoluble solids to water-wet.

Filtration control agents

To provide filtration control, add organophilic lignite or various asphaltic materials. Filtration control products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
DURATONE HT	Controls fluid loss at elevated temperatures; provides high-temperature stability (325°F [163°C]) *Note: When used with 100% ester systems, BARACTIVE polar activator is required to activate DURATONE HT.*	Organophilic leonardite	1-25 (3-71)
AK-70	Controls fluid loss at temperatures up to 275°F (135°C)	Blend of air-blown asphalt and clay with anti-caking agent	1-25 (3-71)
BARABLOK	Controls fluid loss at temperatures up to 325°F (163°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)
BARABLOK 400	Controls fluid loss at temperatures up to 400°F (204°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)

Table 13-19: Filtration control products. These products provide filtration control in PETROFREE LE systems.

XP-07 Overview

XP-07 systems are synthetic based systems in which the continuous or external phase is a pure normal-alkane mixture. The properties of XP-07 systems are influenced by:

- Alkane (synthetic)/water ratio
- Gellant and emulsifier concentrations
- Solids content
- Downhole temperature and pressure

Note: XP-07 fluids can be formulated for stability at temperatures in excess of 450°F (232°C).

XP-07 systems

XP-07 systems are classified in two categories: XP-07 and XP-07 100. Table 13-20 outlines the primary uses of these two systems.

System	Application
XP-07	For deepwater, extended reach, high angle, and HPHT drilling where environmental regulations require synthetic based systems.
XP-07 100	For nondamaging coring and drilling where environmental regulations require synthetic based systems.

Table 13-20: XP-07 systems. XP-07 systems were developed to meet specific drilling requirements.

XP-07

XP-07 systems use emulsifiers, gellants, and fluid loss agents at concentrations based on formation, well geometry, and bottom hole temperature criteria. Table 13-21 provides guidelines for formulating XP-07 systems.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3) to 325°F (163°C)
XP-07	Continous phase	As needed
EZ MUL 2F	Emulsifier	6-20 (17-57.0)
Lime	Alkalinity source	2-10 (6-29)
DURATONE HT	Fluid-loss control agent	2-20 (6-57.0)
Water	Discontinuous phase	As needed
GELTONE II/V	Viscosifier	2-10 (6-29)
SUSPENTONE	Suspension agent	0.5-4 (1.4-11)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed
$CaCl_2$	Salinity source	As needed

Table 13-21: XP-07 system formulation guidelines. This table lists typical product concentrations for XP-07 systems with a stability up to 325°F (163°C).

XP-07 100

XP-07 100 all n-alkane systems are used when maintaining the native state of the geologic formation is a primary concern and environmental regulations require the use of a synthetic based system. These systems are not normally used where water contamination is a known problem. Table 13-22 provides guidelines for formulating XP-07 100 systems.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3) to 325°F (163°C)
XP-07 base	Continous phase	As needed
EZ-CORE	Passive emulsifier	2 (6)
* EZ MUL 2F	Emulsifier	0-4 (0-11)
BARABLOK or BARABLOK 400 or DURATONE HT	Filtration control agent	5-15 (14-43)
GELTONE II/V	Viscosifier	8-16 (23-46)
BARACTIVE	Polar additive	4-12 (11-34)
BAROID, BARODENSE, or BARACARB	Weighting agent	As needed
Lime	Alkalinity source	0-10 (0-29)

Table 13-22: XP-07 100 system formulation guidelines. This table lists typical product concentrations for XP-07 systems with a stability up to 325°F (163°C).

* EZ MUL 2F may be added when a large amount of water contamination occurs.

Note: When using DURATONE HT for filtration control, BARACTIVE must be used as an activator.

Note: For high temperature applications (350-425°F) see Chapter 8, *BAROID 100 HT* .

Mud management

When maintaining a XP-07 system, observe the following guidelines:

- Allow several hours at maximum shear when mixing new mud volume.
- Maintain an all-alkane HTHP filtrate.
- Maintain excess lime at 1 to 3 lb/bbl (3 to 9 kg/m^3)
- Maintain electrical stability above 400 volts.
- Do not use cellulosic LCM.
- Slowly add EZ MUL 2F slowly when weighting agents are added to help oil-wet the additional solids.
- Do not add weighting agents when adding water.
- Use solids control equipment to prevent build-up of low- gravity solids.
- Do not saturate the water phase with $CaCl_2$, emulsion instability and water-wetting of solids can occur.
- Use OMC 42 when a thinner is required.
- Do not add any materials that contain petroleum hydrocarbons.
- Maintain synthetic/water ratio within the programmed range. Table 13-23 lists typical synthetic/water ratios.

Mud density, lb/gal (sg)	Recommended synthetic/water ratio
9-11 (1.08-1.32)	60/40 - 70/30
11-13 (1.32-1.56)	70/30 - 80/20
13-15 (1.56-1.80)	80/20
15-16 (1.80-1.92)	80/20 - 85/15
16-17 (1.92-2.04)	85/15 - 90/10
17-18 (2.04-2.16)	90/10 - 95/5

Table 13-23: Synthetic/water ratios. This table lists the recommended synthetic/water ratios for given mud density.

Logging

XP-07 systems do not conduct electric current; therefore, do not use logging tools that require electric conductance to measure resistivity. Table 13-24 provides guidelines for logging in XP-07 systems.

Objective	Tool	Notes
Depth control correlation and lithology	Induction/gamma ray log Formation density log Sonic log Neutron log Dipmeter	Use the gamma ray log to determine sand and shale sequences. Use the other logs for identifying complex lithology.
Percent shale in shaley sands	Gamma ray log	The gamma ray log method replaces the sand/shale index found in fresh waters from the SP log.
Net sand (sand count)	Formation density log Gamma ray log	Use the formation density log and/or the caliper log to determine sand count when the sand and shale densities differ.
Detect hydrocarbon-bearing formations	Induction/gamma ray log Sonic log Neutron log	High resistivity values indicate hydrocarbon pore saturation. Use a formation density log in conjunction with neutron and sonic logs to identify hydrocarbons.
Interpretation • Water saturation • Porosity • Permeability • Structural formation • Productivity	Induction, sonic, density, and neutron logs Formation density, sonic, and neutron logs; sidewall cores Sidewall cores Continuous dipmeter Formation tester	Use Archie's equation to compute water saturation.

Table 13-24: Logging guidelines. A variety of logs are available to help determine downhole conditions.

Product Information

Viscosifiers/ suspending agents

Use GELTONE II or V to impart rheological properties to the XP-07 system. Use SUSPENTONE to minimize barite sag at elevated temperatures. Use RM-63 to enhance low shear-rate viscosities of the XP-07 systems. Viscosifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
GELTONE II/V	Develops viscosity and suspension properties	Organophilic clay	2-16 (6-46)
SUSPENTONE	Provides suspension and minimize sag with minimal viscosity build-up	Organophilic clay	1-5 (3-14)
RM-63	Enhances low-shear rheological properties	Polymeric fatty acid	0.5-2 (1.4-6)

Table 13-25: Viscosifying products. A variety of products are available to increase rheological properties or enhance low shear-rate viscosities of XP-07 systems.

Thinners

To thin XP-07 systems, add XP-07 base fluid to the system or treat with a polycarboxylic acid or oligomeric fatty acid derivatives. Thinning products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
OMC 2	Extreme viscosity reducer	Oligomeric fatty acid	0.2-1 (0.6-3)
OMC 42	Moderate viscosity reducer	Polymer imide surfactant	0.5-4 (1.4-11)

Table 13-26: Thinning products. Thinning products are used to reduce yield point and gel strengths of XP-07 systems.

Emulsifiers

Use emulsifiers to increase the stability of the XP-07 system emulsion, promote alkane wetting of solids, and prevent water-in-filtrate. Emulsifying products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
EZ-CORE	Acts as a passive emulsifier in the XP-07 100 systems	Refined tall oil fatty acid	2-4 (6-11)
EZ MUL 2F	Acts as a primary emulsifier and alkane-wetting agent	Polyamide in XP-07 base solvent	2-20 (6-57)
DRILTREAT	Alkane-wetting agent	Lecithin dispersion	.5-2 (1.4-6)

Table 13-27: Emulsifying products. Emulsifiers increase emulsion stability and reduce the tendency of insoluble solids to water-wet.

Filtration control agents

To provide HPHT filtration control in XP-07 systems, add organophilic lignite or various asphaltic materials. Filtration control products include:

Product	Application	Description	Treatment, lb/bbl (kg/m^3)
DURATONE HT	HPHT filtration control in XP-07 systems for temperatures to 450°F (232°C)	Organophilic lignite	2-20 (6-57)
AK-70	Controls fluid loss at temperatures up to 275°F (135°C)	Blend of air-blown asphalt and clay with anti-caking agent	1-25 (3-71)
BARABLOK	Controls fluid loss at temperatures up to 325°F (163°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)
BARABLOK 400	Controls fluid loss at temperatures up to 400°F (204°C)	Powdered hydrocarbon resin (asphaltite)	1-15 (3-43)

Table 13-28: Filtration control products. These products provide filtration control in XP-07 systems.

CHAPTER 14

Tables, charts, and calculations

The Complete Fluids Company

Contents

Overview

Tables and charts are grouped by function and separated into logical groups. Use the table of contents to locate the desired section. In each separate section, the items are listed alphabetically.

Formulas for adjusting drilling fluid properties

Formulas for calculating material requirements to increase mud weight

Weight-up calculations (volume increase tolerated)

Use the following formulas to calculate the amount of weight material required to increase the density of a drilling fluid when a volume increase can be tolerated.

$$B = \left[\frac{(350.5)(\rho_{WM})(W_F - W_I)}{(8.3454)(\rho_{WM}) - W_F}\right] \times V_I$$

$$V = \frac{B}{(350.5)(\rho_{WM})}$$

Where

- B is the weight material to add, lb
- V_I is the starting volume of mud, bbl
- ρ_{WM} is the specific gravity of the weight material
- W_F is the desired mud weight, lb/gal
- W_I is the starting mud weight, lb/gal
- V is the volume increase, bbl

Weight-up calculations (final volume specified)

Use the following formulas to calculate a starting volume of mud and amount of weight material required to increase the density of a drilling fluid when the final volume is specified.

$$V_I = \left[\frac{(8.3454)(\rho_{WM}) - W_F}{(8.3454)(\rho_{WM}) - W_I}\right] \times V_D$$

$$B = (V_D - V_I)(\rho_{WM})(350.5)$$

Where

- V_I is the starting volume of mud, bbl
- ρ_{WM} is the specific gravity of the weight material
- W_F is the desired mud weight, lb/gal
- W_I is the starting mud weight, lb/gal
- V_D is the desired final volume, bbl
- B is the weight material to add, lb

Formulas for calculating material requirements to decrease mud weight

Decrease mud weight (volume increase tolerated)

Use the following formula to calculate the volume of dilution fluid required to decrease the density of a drilling fluid when a volume increase can be tolerated.

$$V_{DF} = V_I\left[\frac{W_I - W_F}{W_F - (8.3454)(\rho_{DF})}\right]$$

Where

- V_{DF} is the volume of dilution fluid required, bbl
- V_I is the starting volume of mud, bbl
- W_I is the starting mud weight, lb/gal
- W_F is the final mud weight, lb/gal
- ρ_{DF} is the specific gravity of the dilution fluid

Decrease mud weight (final volume specified)

Use the following formula to calculate the starting volume of mud and a volume of dilution fluid required to decrease the density of a drilling fluid when the final volume is specified.

$$V_I = \left[\frac{(8.3454)(\rho_{DF}) - W_F}{(8.3454)(\rho_{DF}) - W_I}\right] \times V_D$$

$$V_{DF} = V_D - V_I$$

Where

- V_I is the starting volume of mud, bbl
- ρ_{DF} is the specific gravity of the dilution fluid
- W_F is the desired mud weight, lb/gal
- W_I is the starting mud weight, lb/gal
- V_D is the desired final volume, bbl
- V_{DF} is the volume of dilution fluid to add, bbl

Formulas for calculating material requirements to change oil/water ratio (OWR)

Use the following formulas to calculate the volume of oil or water required to change the oil/water ratio of a mud when a volume increase can be tolerated.

Increase oil/water ratio

Increase the oil/water ratio by adding oil using the following formulas.

$$P_W = \frac{R_W}{(R_W + R_O + V_O)}$$

Or

$$V_O = \frac{R_W}{P_W} - R_W - R_O$$

$$W_R = \frac{W_I + (8.3454)(\rho_O)(V_O)}{1 + V_O}$$

Where

- V_O is the volume of oil to be added, bbl/bbl mud
- R_O is the % oil from retort, decimal equivalent
- R_W is the % water from retort, decimal equivalent
- P_W is the new % by volume water in the liquid phase, decimal equivalent
- W_R is the resulting mud weight, lb/gal
- W_I is the starting mud weight, lb/gal
- ρ_O is the specific gravity of the oil

Decrease oil/water ratio

Decrease the oil/water ratio by adding water using the following formulas.

$$P_O = \frac{R_O}{(R_O + R_W + V_W)}$$

Or

$$V_W = \frac{R_O}{P_O} - R_O - R_W$$

$$W_R = \frac{W_I + (8.3454)(V_W)}{1 + V_W}$$

Where

- V_W is the volume of water to be added, bbl/bbl mud
- R_O is the % oil from retort, decimal equivalent
- R_W is the % water from retort, decimal equivalent
- P_O is the new % by volume oil in the liquid phase, decimal equivalent
- W_R is the resulting mud weight, lb/gal
- W_I is the starting mud weight, lb/gal

Calculate the amount of weight material required to increase density back to original density. See the sections titled *Weight-up calculations* above.

Formulas for calculating area and volume

Formulas for calculating pit and tank volume

Rectangular tank

Note: All dimensions are expressed in feet.

$$\text{Volume(bbl)} = \frac{\text{length} \times \text{width} \times \text{height}}{5.6146}$$

$$\text{Volume(bbl/ft)} = \frac{\text{length} \times \text{width}}{5.6146}$$

$$\text{Volume(bbl/in)} = \frac{\text{length} \times \text{width}}{67.375}$$

Vertical cylindrical tank

$$\text{Volume(bbl)} = \frac{(\text{diameter})^2 \times \text{height}}{7.1486}$$

$$\text{Volume(bbl/ft)} = \frac{(\text{diameter})^2}{7.1486}$$

$$\text{Volume(bbl/in)} = \frac{(\text{diameter})^2}{85.7833}$$

Horizontal cylindrical tank (half full or less)

$$\text{Volume (bbl)} = \frac{\left(0.3168\,d\,h + 1.403\,h^2 - 0.933\,\frac{h^3}{d}\right) \times \text{length}}{5.6146}$$

Where

- *h* is the height of the fluid level, ft
- *d* is the diameter of the tank, ft

Horizontal cylindrical tank (more than half full)

$$\text{Volume(bbl)} = \frac{(\text{diameter})^2 \times \text{length}}{7.1486} - \frac{\left(0.3168\,d\,h + 1.403\,h^2 - 0.933\,\frac{h^3}{d}\right) \times \text{length}}{5.6146}$$

Where

- *h* is the height of the empty portion of the tank, ft
- *d* is the diameter of the tank, ft

Formulas for calculating hole volume

Note: All diameters are expressed in inches; section lengths are expressed in feet.

Hole volume (with no drillstring in the hole)

$$\text{Volume(bbl)} = \text{section length} \times \frac{(\text{hole diameter})^2}{1029.4}$$

$$\text{Volume(bbl/ft)} = \frac{(\text{hole diameter})^2}{1029.4}$$

Annular volume (capacity)

$$\text{Volume (bbl)} = \text{section length} \times \frac{(\text{hole diameter})^2 - (\text{pipe diameter})^2}{1029.4}$$

$$\text{Volume(bbl/ft)} = \frac{(\text{hole diameter})^2 - (\text{pipe diameter})^2}{1029.4}$$

Drillpipe or drill collar capacity and displacement

$$\text{Capacity (bbl/ft)} = \frac{(\text{inside diameter})^2}{1029.4}$$

Displacement (bbl/ft) =

$$\frac{(\text{outside diameter})^2 - (\text{inside diameter})^2}{1029.4}$$

Calculations (metal only with couplings)

0.002 × (weight of pipe/ft with couplings) × (depth, ft) = Displacement of pipe, ft^3

0.000367 × (Weight of pipe/ft with couplings) × (depth, ft) = Displacement of pipe, bbl

Dimensions

Casing dimensions

The following table gives weights for casing with couplings.

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
4	3.732	5.56
	3.550	9.26
	3.550	9.50
	3.480	11.0
	3.430	11.60
	3.364	12.60

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
4 1/2	4.216	6.75
	4.090	9.50
	4.052	10.50
	4.030	10.98
	4.026	11.00
	4.000	11.60
	3.990	11.75
	3.958	12.60
	3.960	12.75
	3.920	13.50
	3.826	15.10
	3.826	16.60
	3.640	18.80
	3.500	21.60
	3.380	24.60
	3.240	26.50
4 3/4	4.364	9.50
	4.082	16.00
	4.070	16.50
	4.000	18.00
	3.910	20.00
	3.850	21.00
5	4.696	8.00
	4.560	11.50

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
5	4.500	12.85
	4.494	13.00
	4.450	14.00
	4.408	15.00
	4.276	18.00
	4.184	20.30
	4.154	21.00
	4.044	23.20
	4.000	24.20
5 1/4	4.944	8.50
	4.886	10.00
	4.768	13.00
	4.650	16.00
5 1/2	5.192	9.00
	5.044	13.00
	5.012	14.00
	4.974	15.00
	4.950	15.50
	4.892	17.00
	4.778	20.00
	4.670	23.00
	4.580	25.00
	4.548	26.00

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
5 1/2	4.276	32.30
	4.090	36.40
5 3/4	5.290	14.00
	5.190	17.00
	5.090	19.50
	5.090	20.00
	4.990	22.50
	4.990	23.00
	4.890	25.20
6	5.672	10.50
	5.524	15.00
	5.50	16.00
	5.450	17.00
	5.424	18.00
	5.352	20.00
	5.240	23.00
	5.140	26.00
6 5/8	6.287	12.00
	6.260	13.00
	6.135	17.00
	6.049	20.00
	5.980	22.00
	5.921	24.00
	5.880	25.00

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
6 5/8	5.855	26.00
	5.837	26.80
	5.791	28.00
	5.761	29.00
	5.675	31.80
	5.675	32.00
	5.595	34.00
7	6.652	13.00
	6.538	17.00
	6.456	20.00
	6.398	22.00
	6.366	23.00
	6.336	24.00
	6.276	26.00
	6.214	28.00
	6.184	29.00
	6.168	29.80
	6.154	30.00
	6.094	32.00
	6.048	33.70
	6.004	35.00
	5.920	38.00
	5.836	40.20

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
7	5.820	41.00
	5.736	43.00
	5.720	44.00
	5.540	49.50
7 5/8	7.263	14.75
	7.125	20.00
	7.025	24.00
	6.969	26.40
	6.875	29.70
	6.765	33.70
	6.760	34.00
	6.710	35.50
	6.655	38.00
	6.625	39.00
	6.445	45.00
	6.435	45.30
7 3/4	6.560	46.10
8	7.528	20.00
	7.386	26.00
8 1/8	7.485	28.00
	7.385	32.00
	7.285	35.50
	7.285	36.00
	7.185	39.50

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
8 1/8	7.185	40.00
	7.125	42.00
8 5/8	8.191	20.00
	8.097	24.00
	8.017	28.00
	7.921	32.00
	7.825	36.00
	7.775	38.00
	7.725	40.00
	7.651	43.00
	7.625	44.00
	7.537	48.00
	7.511	49.00
	7.435	52.00
9	8.290	34.00
	8.196	38.00
	8.150	40.00
	8.150	41.20
	8.032	45.00
	8.032	46.10
	7.910	50.20
	7.810	54.00
	7.812	55.20

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
9 5/8	9.063	29.30
	9.001	32.30
	8.921	36.00
	8.885	38.00
	8.835	40.00
	8.799	42.00
	8.755	43.50
	8.750	44.30
	8.681	47.00
	8.680	47.20
	8.535	53.50
	8.450	57.40
	8.435	58.40
	8.375	61.10
10	9.384	33.00
	9.200	41.50
	9.120	45.50
	9.016	50.50
	8.908	55.50
	8.790	61.20
	8.780	60.00
10 3/4	10.192	32.75
	10.140	35.75
	10.050	40.50

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
10 3/4	9.950	45.50
	9.950	46.20
	9.902	48.00
	9.850	49.50
	9.850	51.00
	9.784	54.00
	9.760	55.50
	9.660	60.70
	9.560	65.70
	9.450	71.10
	9.350	76.00
	9.250	81.00
11	10.552	26.75
11 3/4	11.15	38.00
	11.084	42.00
	11.00	47.00
	10.950	50.00
	10.880	54.00
	10.772	60.00
	10.770	61.00
	10.682	65.00
12	11.514	31.50
	11.384	40.00

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
12 3/4	12.250	33.38
	12.188	37.42
	12.126	41.45
	12.130	43.00
	12.090	43.77
	12.062	45.58
	12.000	49.56
	11.970	53.00
13	12.438	40.00
	12.360	45.00
	12.282	50.00
	12.200	54.00
13 3/8	12.715	48.00
	12.615	54.50
	12.515	61.00
	12.415	68.00
	12.347	72.00
	12.275	77.00
	12.175	83.00
	12.175	83.50
	12.159	85.00
	12.031	92.00
	11.937	98.00

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
14	13.448	42.00
	13.344	50.00
15	14.418	47.50
16	15.396	52.50
	15.375	55.00
	15.250	65.00
	15.198	70.00
	15.124	75.00
	15.010	84.00
	14.688	109.00
	14.570	118.00
18	17.180	80.00
18 5/8	17.855	78.00
	17.755	87.50
	17.655	96.50
20	19.190	90.00
	19.124	94.00
	19.000	106.50
	18.730	133.00
	18.376	169.00
21 1/2	20.710	92.50
	20.610	103.00
	20.510	114.00

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with coupling, lb
24 1/2	23.850	88.00
	23.750	100.50
	23.650	113.00
30	29.376	98.93
	29.250	118.65
	29.000	157.53
	28.750	196.08
	28.500	234.29
	28.000	309.72
	27.750	346.93
	27.500	383.81
	27.000	456.57

Cylinder capacities

Capacity of a long cylinder

$\text{bbl/100 ft} = 0.0972\ D^2$

$\text{bbl/inch} = 0.000081\ D^2$

$\text{bbl/1,000 ft} = 0.972\ D^2$

$\text{ft/bbl} = 1029 \div D^2$

Where *D* is the diameter of the cylinder, in

Inside diameter of a steel cylinder

$$ID = \sqrt{OD^2 - 0.3745W}$$

Where

- *OD* is the outside diameter, in
- *W* is the weight, lb/ft

Drillpipe dimensions

The following table gives weights for drillpipes with tool joints.

Outside diameter, in	Inside diameter, in	Wt/ft with tool joints, lb
1.9	1.5	3.75
2 3/8	2.00	4.80
	1.995	4.85
	1.815	6.65
2 7/8	2.469	6.45
	2.441	6.85
	2.323	8.35
	2.151	10.40
3 1/2	3.063	8.50
	2.992	9.50
	2.900	11.20
	2.764	13.30
	2.602	15.25
	2.602	15.50
3 7/8	3.181	14.50
4	3.500	10.40
	3.476	11.85
	3.382	12.50

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with tool joints, lb
4	3.340	14.00
	3.244	15.30
	3.240	15.70
4 1/2	4.00	12.75
	3.958	13.75
	3.826	16.60
	3.754	18.10
	3.640	20.00
4 3/4	4.00	19.08
5	5.00	14.20
	4.408	15.00
	4.408	16.25
	4.276	18.35
	4.276	18.35
	4.214	20.50
	4.00	25.60
5 1/2	4.778	21.90
	4.670	23.25
	4.670	24.70
5 3/4	5.00	23.40
5 9/16	4.975	19.00
	4.859	22.20
	4.733	23.30
	4.733	25.25

(continued on next page)

Outside diameter, in	Inside diameter, in	Wt/ft with tool joints, lb
6 5/8	6.065	22.20
	5.965	23.30
	5.965	25.20
	5.761	31.90
7 5/8	6.965	28.75
	6.969	29.25
8 5/8	7.825	40.00
	7.625	46.50

Tubing dimensions

The following table gives weights for tubing.

Outside diameter, in	Inside diameter, in	Weight/ft, lb
0.75	0.636	0.42
1.00	0.866	0.67
1.050	0.824	1.14
	0.824	1.20
	0.742	1.55

(continued on next page)

Outside diameter, in	Inside diameter, in	Weight/ft, lb
1.315	1.125	1.30
	1.097	1.43
	1.065	1.63
	1.049	1.70
	1.049	1.72
	1.049	1.80
	1.049	1.90
	0.957	2.25
	0.957	2.30
1.660	1.410	2.10
	1.380	2.30
	1.380	2.40
	1.278	3.02
	1.264	3.24
	1.264	3.29
1.900	1.650	2.40
	1.610	2.75
	1.610	2.90
	1.500	3.64
	1.462	4.19
2	1.670	3.30
	1.670	3.40

(continued on next page)

Outside diameter, in	Inside diameter, in	Weight/ft, lb
2 1/16	1.813	2.66
	1.750	3.25
	1.613	4.50
2 3/8	2.125	3.10
	2.107	3.32
	2.041	4.00
	1.995	4.60
	1.995	4.70
	1.947	5.00
	1.939	5.30
	1.867	5.80
	1.867	5.95
	1.853	6.20
	1.703	7.70
2 7/8	2.579	4.36
	2.563	4.64
	2.469	5.90
	2.441	6.40
	2.441	6.50
	2.323	7.90
	2.259	8.60
	2.259	8.70
	2.195	9.50

(continued on next page)

Outside diameter, in	Inside diameter, in	Weight/ft, lb
2 7/8	2.151	10.40
	2.091	10.70
	2.065	11.00
	1.995	11.65
3 1/2	3.188	5.63
	3.068	7.70
	3.018	8.50
	3.018	8.90
	2.992	9.20
	2.992	9.30
	2.992	10.20
	2.992	10.30
	2.900	11.20
	2.750	12.70
	2.764	12.80
	2.750	12.95
	2.764	13.30
	2.602	14.90
	2.602	15.50
	2.548	15.80
	2.480	16.70
	2.440	17.05
4	3.548	9.25
	3.548	9.40

(continued on next page)

Outside diameter, in	Inside diameter, in	Weight/ft, lb
4	3.548	9.50
	3.476	10.80
	3.476	10.90
	3.476	11.00
	3.428	11.60
	3.340	13.30
	3.340	13.40
	3.000	19.00
	2.780	22.50
4 1/2	4.026	11.00
	3.990	11.80
	3.958	12.60
	3.958	12.75
	3.920	13.50
	3.826	15.40
	3.826	15.50
	3.754	16.90
	3.640	19.20
	3.500	21.60
	3.380	24.60
	3.240	26.50

Formulas for calculating pump output

Duplex pump

$$\text{Pump output} = \frac{\text{efficiency}}{100} \times \frac{(2\ \text{liner}^2 - \text{rod diameter}^2) \times \text{stroke}}{6176.4}$$

Triplex pump

Pump output (bbl/stroke) =
$(\text{liner inside diameter})^2 \times 0.000243 \times \text{stroke length}$

Pumps

Duplex pump capacities

The capacities of duplex pumps are given in barrels per cycle at different liner bores and strokes.

Note: No allowance is made for the volume occupied by the pump rods.

Liner bore, in (mm)	Stroke, in (mm)	Volume, bbl/cycle (L) at 100% pump efficiency
4.00 (102)	10 (254)	0.0518 (8.24)
4.50 (114)	10 (254)	0.0656 (10.4)
5.00 (127)	10 (254)	0.0810 (12.9)
5.25 (133)	10 (254)	0.0893 (14.2)
5.50 (140)	10 (254)	0.098 (15.6)
5.75 (146)	10 (254)	0.107 (17.0)
6.00 (152)	10 (254)	0.117 (18.6)

(continued on next page)

Liner bore, in (mm)	Stroke, in (mm)	Volume, bbl/cycle (L) at 100% pump efficiency
6.25 (159)	10 (254)	0.127 (20.2)
6.50 (165)	10 (254)	0.137 (21.8)
6.75 (171)	10 (254)	0.148 (23.5)
7.00 (178)	10 (254)	0.159 (25.3)
7.25 (184)	10 (254)	0.170 (27.0)
6.00 (152)	12 (305)	0.140 (22.3)
6.25 (159)	12 (305)	0.152 (24.2)
6.50 (165)	12 (305)	0.161 (25.6)
6.75(171)	12 (305)	0.177 (28.1)
7.00 (178)	12 (305)	0.190 (30.2)
7.25 (184)	12 (305)	0.204 (32.4)
6.00 (152)	14 (356)	0.163 (25.9)
6.25 (159)	14 (356)	0.177 (28.1)
6.50 (165)	14 (356)	0.192 (30.5)
6.75 (171)	14 (356)	0.207 (32.9)
7.00 (178)	14 (356)	0.222 (35.3)
7.25 (184)	14 (356)	0.238 (37.8)
6.25 (159)	16 (406)	0.202 (32.1)
6.50 (165)	16 (406)	0.219 (34.8)
6.75 (171)	16 (406)	0.236 (37.5)
7.00 (178)	16 (406)	0.254 (40.4)
7.25 (184)	16 (406)	0.272 (43.2)

(continued on next page)

Liner bore, in (mm)	Stroke, in (mm)	Volume, bbl/cycle (L) at 100% pump efficiency
6.00 (156)	18 (451)	0.210 (33.4)
6.25 (159)	18 (451)	0.228 (36.3)
6.50 (165)	18 (451)	0.246 (39.1)
6.75 (171)	18 (451)	0.266 (42.3)
7.00 (178)	18 (451)	0.286 (45.5)
7.25 (184)	18 (451)	0.306 (48.7)
7.50 (191)	18 (451)	0.328 (52.2)
7.75 (197)	18 (451)	0.350 (55.7)
6.00 (156)	20 (508)	0.233 (37.0)
6.25 (159)	20 (508)	0.253 (40.2)
6.50 (165)	20 (508)	0.274 (43.6)
6.75 (171)	20 (508)	0.295 (46.9)
7.00 (178)	20 (508)	0.317 (50.4)
7.25 (184)	20 (508)	0.340 (54.1)
7.50 (191)	20 (508)	0.364 (57.9)
7.75 (197)	20 (508)	0.389 (61.9)
8.00 (203)	20 (508)	0.414 (65.8)
7.00 (178)	22 (559)	0.349 (55.5)
7.25 (184)	22 (559)	0.374 (59.5)
7.5O (191)	22 (559)	0.401 (63.8)
7.75 (197)	22 (559)	0.428 (68.1)
8.00 (203)	22 (559)	0.456 (72.5)
8.25 (210)	22 (559)	0.485 (77.1)
8.50 (216)	22 (559)	0.515 (81.9)

(continued on next page)

Liner bore, in (mm)	Stroke, in (mm)	Volume, bbl/cycle (L) at 100% pump efficiency
8.75 (222)	22 (559)	0.545 (86.7)
9.00 (229)	22 (559)	0.577 (91.7)
9.25 (235)	22 (559)	0.610 (97.0)
8.00 (203)	24 (610)	0.497 (79.0)
8.25 (210)	24 (610)	0.529 (84.1)
8.50 (216)	24 (610)	0.562 (89.4)
8.75 (222)	24 (610)	0.595 (94.6)
9.00 (229)	24 (610)	0.630 (100.2)
9.25 (235)	24 (610)	0.665 (105.7)
9.75 (248)	24 (610)	0.739 (117.5)
10.00 (254)	24 (610)	0.777 (123.5)

Triplex pump capacities

The following tables give capacities for various stroke triplex pumps.

7-inch stroke triplex pump, bbl/cycle

Diameter, in (mm)	Stroke, in (mm)	Displacement, bbl/cycle (L)
7.00 (178)	7 (178)	0.083 (13.25)
6..50 (165)	7 (178)	0.072 (11.43)
6.00 (152)	7 (178)	0.061 (9.73)
5.00 (140)	7 (178)	0.051 (8.18)
5.00 (127)	7 (178)	0.043 (6.78)
4.50 (11)	7 (178)	0.035 (5.49)

8-inch stroke triplex pump

Diameter, in (mm)	Stroke, in (mm)	Displacement/cycle, bbl (L)
6.25 (159)	8 (203)	0.076 (12.07)
6.00 (152)	8 (203)	0.070 (11.13)
5.50 (140)	8 (203)	0.059 (9.35)
5.00 (127)	8 (203)	0.049 (7.72)
4.50 (114)	8 (203)	0.039 (6.25)
4.00 (102)	8 (203)	0.031 (4.96)

9-inch stroke triplex pump

Diameter, in (mm)	Stroke, in (mm)	Displacement/cycle, bbl (L)
7.00 (178)	9 (229)	0.107 (17.03)
6.50 (165)	9 (229)	0.092 (14.69)
6.25 (159)	9 (229)	0.085 (13.55)
6.00 (152)	9 (229)	0.079 (12.49)
5.50 (140)	9 (229)	0.066 (10.48)
5.00 (127)	9 (229)	0.055 (8.66)
4.50 (114)	9 (229)	0.044 (7.04)

11-inch stroke triplex pump

Diameter, in (mm)	Stroke, in (mm)	Displacement/cycle, bbl (L)
7.00 (178)	11 (279)	0.130 (20.82)
6.50 (165)	11 (279)	0.113 (17.94)
6.00 (152)	11 (279)	0.096 (15.29)
5.5 0 (140)	11 (279)	0.081 (12.83)

Chemical properties

The following table identifies the chemical properties of some elements used in the oilfield.

Element	Symbol	Atomic weight	Atomic number
Aluminum	Al	26.98	13
Arsenic	As	74.92	33
Barium	Ba	137.36	56
Bromine	Br	79.916	35
Calcium	Ca	40.08	20
Carbon	C	12.011	6
Cesium	Cs	132.91	55
Chlorine	Cl	35.457	17
Chromium	Cr	52.01	24
Copper	Cu	63.54	29
Fluorine	F	19	9
Hydrogen	H	1.008	1
Iodine	I	126.91	53
Iron	Fe	55.85	26

(continued on next page)

Element	Symbol	Atomic weight	Atomic number
Lead	Pb	207.21	82
Lithium	Li	6.94	3
Magnesium	Mg	24.32	12
Manganese	Mn	54.94	25
Mercury	Hg	200.61	80
Nitrogen	N	14.008	7
Oxygen	O	16	8
Phosphorous	P	30.975	15
Potassium	K	39.1	19
Silicon	Si	28.09	14
Silver	Ag	107.873	47
Sodium	Na	22.991	11
Sulfur	S	32.066	16
Titanium	Ti	47.9	22
Tungsten	W	183.86	74
Zinc	Zn	65.38	30

Periodic table of the elements

Figure 14-1 on the following page shows how chemical elements are physically related to one another.

1a																	0
1 H Hydrogen 1.0079	2a		1 H Hydrogen 1.0079	Atomic number Symbol Element name Atomic weight (if in brackets, it is mass number of the most stable isotope								3a	4a	5a	6a	7a	2 He Helium 4.002602
3 Li Lithium 6.941	4 Be Beryllium 9.012182											5 B Boron 10.81	6 C Carbon 12.011	7 N Nitrogen 14.0067	8 O Oxygen 15.9994	9 F Fluorine 18.998403	10 Ne Neon 20.180
11 Na Sodium 22.98977	12 Mg Magnesium 24.305	3b	4b	5b	6b	7b	(	8b	)	1b	2b	13 Al Aluminum 26.98154	14 Si Silicon 28.0855	15 P Phosphorus 30.973762	16 S Sulfur 32.07	17 Cl Chlorine 35.453	18 Ar Argon 39.948
19 K Potassium 39.0983	20 Ca Calcium 40.078	21 Sc Scandium 44.95591	22 Ti Titanium 47.88	23 V Vanadium 50.9415	24 Cr Chromium 51.996	25 Mn Manganese 54.93805	26 Fe Iron 55.847	27 Co Cobalt 58.93320	28 Ni Nickel 58.6934	29 Cu Copper 63.546	30 Zn Zinc 65.39	31 Ga Gallium 69.723	32 Ge Germanium 72.61	33 As Arsenic 74.92159	34 Se Selenium 78.96	35 Br Bromine 79.904	36 Kr Krypton 83.80
37 Rb Rubidium 85.4678	38 Sr Strontium 87.62	39 Y Yttrium 88.90585	40 Zr Zirconium 91.224	41 Nb Niobium 92.90638	42 Mo Molybdenum 95.94	43 Tc Technetium [97.9072]	44 Ru Ruthenium 101.07	45 Rh Rhodium 102.90550	46 Pd Palladium 106.42	47 Ag Silver 107.8682	48 Cd Cadmium 112.41	49 In Indium 114.818	50 Sn Tin 118.71	51 Sb Antimony 121.757	52 Te Tellurium 127.60	53 I Iodine 126.90447	54 Xe Xenon 131.29
55 Cs Cesium 132.9054	56 Ba Barium 137.33	57 * La Lanthanum 138.9055	72 Hf Hafnium 178.49	73 Ta Tantalum 180.9479	74 W Tungsten 183.84	75 Re Rhenium 186.207	76 Os Osmium 190.23	77 Ir Iridium 192.22	78 Pt Platinum 195.08	79 Au Gold 196.96654	80 Hg Mercury 200.59	81 Tl Thallium 204.3833	82 Pb Lead 207.2	83 Bi Bismuth 208.98037	84 Po Polonium [208.9824)]	85 At Astatine [209.9871]	86 Rn Radon [222.0176]
87 Fr Francium [223.0197]	88 Ra Radium [226.0254]	89 * * Ac Actinium [227.0278]	104 Rf Rutherfordium [261.11]	105 Db Hahnium [262.114]	106 Sg Seaborgium [263.118]	107 Bh Neilsborium [262.12]	108 Hs Hassium [265]	109 Mt Meitnerium [266]									
		* Lanthanides		58 Ce Cerium 140.115	59 Pr Praseodymium 140.90765	60 Nd Neodymium 144.24	61 Pm Promethium [144.9127]	62 Sm Samarium 150.36	63 Eu Europium 151.97	64 Gd Gadolinium 157.25	65 Tb Terbium 158.92534	66 Dy Dysprosium 162.50	67 Ho Holmium 164.93032	68 Er Erbium 167.26	69 Tm Thulium 168.93421	70 Yb Ytterbium 173.04	71 Lu Lutetium 174.967
		** Actinides		90 Th Thorium 232.0381	91 Pa Protactinium 231.03588	92 U Uranium 238.0289	93 Np Neptunium [237.0482]	94 Pu Plutonium [244.0642]	95 Am Americium [243.0614]	96 Cm Curium [247.0703]	97 Bk Berkelium [247.0703]	98 Cf Californium [251.0796]	99 Es Einsteinium [252.083]	100 Fm Fermium [257.0951]	101 Md Mendelevium [258.10]	102 No Nobelium [259.1009]	103 Lr [262.11]

Figure 14-1: Periodic Table of the elements. This table shows elements with similar chemical behavior in vertical groups

Chemical conversions

Epm to ppm conversion

The following table lists the equivalent weight of various cations and anions.

Ion	Equivalent weight
Ca^{+2}	20.0
Mg^{+2}	12.2
Fe^{+3}	18.6
Na^{+}	23.0
Cl^{-}	35.5
SO_4^{-2}	48.0
OH^{-}	17.0
CO_3^{-2}	30.0
HCO_3^{-}	61.0
PO_4^{-3}	31.7

Use the following equation to convert concentration in equivalents per million (epm) to parts per million (ppm).

$$\text{Equivalent weight} \times \text{epm} = \text{ppm}$$

Pounds chemical to remove certain contaminants

Contaminant to be removed	Chemical used to remove contaminant	Conversion factor mg/L (contaminant) × factor = lb/bbl chemical to add
Ca^{++}	Soda ash	0.000925
Ca^{++}	Sodium bicarbonate	0.000734
Mg^{++}	Caustic soda	0.00115
CO_3^{-2}	Lime	0.00043
HCO_3^{-1}	Lime	0.00043
H_2S	Lime	0.00076
H_2S	Zinc carbonate	0.00128
H_2S	Zinc oxide	0.000836

Note: Due to the extreme danger associated with hydrogen sulfide (H_2S), it is recommended that a minimum of 1 ½ times the calculated amount of chemical be added.

Physical properties

Bulk volume data

The following table gives approximate bulk volumes for three common materials.

Material	Amount	Approximate bulk volume
AQUAGEL	100 lb	1.67 ft^3
BAROID	100 lb	0.74 ft^3
Cement	94 lb	1 ft^3

Density of common materials

The following table gives specific gravities and densities for common materials.

Material	Specific gravity	lb/gal	lb/bbl
Barite	4.2 to 4.3	35.0 to 35.8	1470 to 1504
Calcium carbonate	2.7	22.5	945
Cement	3.1 to 3.2	25.8 to 26.7	1085 to 1120
Clays and/or drilled solids	2.4 to 2.7	20.0 to 22.5	840 to 945
Diesel oil	0.84	7.0	294
Dolomite	2.8 to 3.0	23.3 to 25.0	980 to 1050
Feldspar	2.4 to 2.7	20.0 to 22.5	840 to 945
Fresh water	1.0	8.33	350
Galena	6.5	54.1	2275
Gypsum	2.3	19.2	805
Halite (rock salt)	2.2	18.3	770
Iron	7.8	65.0	2730
Iron oxide (hematite)	5.1	42.5	1785
Lead	11.4	95.0	3990
Limestone	2.7 to 2.9	22.5 to 24.2	945 to 1015
Slate	2.7 to 2.8	22.5 to 23.3	945 to 980
Steel	7.0- to 8.0	58.3 to 66.6	2450 to 2800

Specific materials

Saltwater data tables

Saltwater constants

The following table gives maximum solubilities of sodium chloride.

Maximum solubility of sodium chloride in water	
Temperature °F (°C)	**% NaCl by weight (in saturated solution)**
32 (0)	26.3
68 (20)	26.5
122 (50)	27.0
212 (100)	28.5

Sodium chloride solution densities

The following table gives densities of aqueous sodium chloride solutions at 68°F (20°C).

sg	% NaCl by wt	Grams NaCl, 100 cm^3 solution	NaCl, lb/ft^3	NaCl, lb/gal	NaCl, lb/bbl
1.0053	1	1.01	0.628	0.84	3.52
1.0125	2	2.03	1.26	0.169	7.10
1.0268	4	4.11	2.56	0.343	14.40
1.0413	6	6.25	3.90	0.521	21.90
1.0559	8	8.45	5.27	0.705	29.61

(continued on next page)

sg	% NaCl by wt	Grams NaCl, 100 cm^3 solution	NaCl, lb/ft^3	NaCl, lb/gal	NaCl, lb/bbl
1.0707	10	10.71	6.68	0.894	37.53
1.0857	12	13.03	8.13	1.09	45.65
1.1009	14	15.41	9.62	1.29	54.01
1.1162	16	17.86	11.15	1.49	62.58
1.1319	18	20.37	12.72	1.70	71.40
1.1478	20	22.96	14.33	1.92	80.47
1.1640	22	25.61	15.99	2.14	89.75
1.1804	24	28.33	17.69	2.36	99.29
1.1972	26	31.13	19.43	2.60	109.12

Seawater composition chemicals

The following table identifies typical chemicals in seawater (average sg = 1.025) and gives their concentrations.

Average composition of sea water		
Constituent	**Parts per million**	**Equivalent parts per million**
Sodium	10440	454.0
Potassium	375	9.6
Magnesium	1270	104.6
Calcium	410	20.4
Chloride	18970	535.0
Sulfate	2720	57.8
Carbon dioxide	90	4.1
Other constituents	80	n/a

Metric and standard conversion factors

The following table gives conversion factors used for converting one unit to another. Both metric-to-standard and standard-to-metric conversion factors are listed.

Multiply	By	To obtain
Atmospheres	14.7	pounds per square inch (psi)
	1.0132	bars
	101.32	kilopascals
Barrels US (bbl)	42	gallons US (gal)
	35	gallons (imperial)
	5.615	cubic feet (ft^3)
	159	liters (L)
	0.159	cubic meters (m^3)
	350	pounds (lb) [H_2O at 68°F]
Barrels/foot (bbl/ft)	42	gallons/ft (gal/ft)
	5.615	cubic ft/ft (ft^3/ft)
	159	liters (L)
	0.159	cubic meters/foot (m^3/ft)
	521.6	liters/meter (L/m)
	0.5216	cubic meters/meter (m^3/m)

(continued on next page)

Multiply	By	To obtain
Barrels/minute (bbl/min)	42	gallons/minute (gal/min)
	5.615	cubic ft/minute (ft^3/min)
	159	liters/minute (L/min)
	0.159	cubic meters/minute (m^3/min)
Bars	0.9869	atmospheres
	14.5	pounds per square inch (psi)
	100	kilopascals
Centimeters (cm)	0.0328	feet (ft)
	0.3937	inches (in)
	0.01	meters (m)
	10	millimeters (mm)
Cubic centimeters (cm^3)	0.0610	cubic inches (in^3)
	0.0010	liters (L)
	1.0	milliliters (mL)
Cubic feet (ft^3)	0.1781	barrels (bbl)
	7.4805	gallons (gal)
	1,728	cubic inches (in^3)
	28,317	cubic centimeters (cm^3)
	28.3170	liters (L)
	0.0283	cubic meters (m^3)

(continued on next page)

Multiply	By	To obtain
Cubic inches (in^3)	16.3871	cubic centimeters (cm^3)
	0.0164	liters (L)
	0.0006	cubic feet (ft^3)
	0.0043	gallons (gal)
Cubic meters (m^3)	6.2898	barrels (bbl)
	264.17	gallons (gal)
	35.31	cubic feet (ft^3)
	61023	cubic inches (in^3)
	1,000,000	cubic centimeters (cm^3)
	1,000	liters (L)
Cubic meters/minute (m^3/min)	6.2898	barrels/minute (bbl/min)
	264.17	gallons/minute (gal/min)
	35.31	cubic feet/minute (ft^3/min)
	1,000	liters/minute (L/min)
Degrees, angle	60	minutes (min)
	0.0175	radians
	3,600	seconds
Degrees, temperature Celsius (°C)	(°C × 1.8) + 32	degrees Fahrenheit (°F)
Degrees, temperature Fahrenheit (°F)	(°F – 32) ÷ 1.8	degrees Celsius (°C)

(continued on next page)

Multiply	By	To obtain
Feet (ft)	30.48	centimeters (cm)
	0.3048	meters (m)
	12	inches (in)
	0.3333	yards (yd)
Feet/minute (ft/min)	0.0167	feet/second (ft/sec)
	0.3048	meters/minute (m/min)
	0.00508	meters/second (m/sec)
Feet/second (ft/sec)	60	feet/minute (ft/min)
	18.288	meters/minute (m/min)
	0.3048	meters/second (m/sec)
Gallons, US (gal)	3785	cubic centimeters (cm^3)
	3.785	liters (L)
	0.0038	cubic meters (m^3)
	231	cubic inches (in^3)
	0.1337	cubic feet (ft^3)
	0.0238	barrels (bbl)
Gallons/minute (gal/min)	0.0238	barrels/minute (bbl/min)
	0.1337	cubic feet/minute (ft^3/min)
	3.785	liters/minute (L/min)
	0.0038	cubic meters/minute (m^3/min)
Grams (g)	0.0010	kilograms (kg)
	1,000	milligrams (mg)
	0.03527	ounces (oz, avoirdupois)
	0.0022	pounds (lb)

(continued on next page)

Multiply	By	To obtain
Grams/liter (g/L)	0.0624	pounds/cubic foot (lb/ft^3)
	0.0083	pounds/gallon (lb/gal)
	0.3505	pounds/barrel (lb/bbl)
	1,000	milligrams/liter (mg/L)
Inches (in)	0.0833	feet (ft)
	0.0278	yards (yd)
	25,400	microns
	25.4	millimeters (mm)
	2.54	centimeters (cm)
	0.0254	meters (m)
Kilograms (kg)	1,000	grams (g)
	0.0010	metric tons
	2.2	pounds (lb)
Kilograms/cubic meter (kg/m^3)	0.3505	pounds/barrel (lb/bbl)
	0.0083	pounds/gallon (lb/gal)
	0.0624	pounds/cubic foot (lb/ft^3)
Kilometers (km)	39,370	inches (in)
	3280.84	feet (ft)
	1,000	meters (m)
	0.6214	miles (mi)

(continued on next page)

Multiply	By	To obtain
Kilometers/hour (km/hr or kph)	54.68	feet/minute (ft/min)
	0.9113	feet/second (ft/sec)
	0.54	knots
	0.6214	miles/hour (mi/hr or mph)
	1,000	meters/hour (m/hr)
	16.6667	meters/minute (m/min)
	0.2778	meters/second (m/sec)
Kilopascals	0.1450	pounds per square inch (psi)
	0.0100	bars
	0.0099	atmospheres
Knots	1.15	miles/hour (mi/hr or mph)
	6,080	feet/hour (ft/hr)
	101.27	feet/minute (ft/min)
	1.69	feet/second (ft/sec)
	1.85	kilometers/hour (km/hr or kph)
	30.87	meters/minute (m/min)
	0.5144	meters/second (m/sec)
Liters (L)	61.03	cubic inches (in^3)
	0.0353	cubic feet (ft^3)
	0.2642	gallons (gal)
	0.0063	barrels (bbl)
	1,000	cubic centimeters (cm^3)
	0.001	cubic meters (m^3)

(continued on next page)

Multiply	By	To obtain
Liters/minute (L/min)	0.2642	gallons/minute (gal/min)
	0.0063	barrels/minute (bbl/min)
	0.0353	cubic feet/minute (ft^3/min)
Meters (m)	1,000	millimeters (mm)
	100	centimeters (cm)
	0.001	kilometers (km)
	39.37	inches (in)
	3.28	feet (ft)
	1.0936	yards (yd)
Meters/minute (m/min)	3.28	feet/minute (ft/min)
	0.05468	feet/second (ft/sec)
	0.03728	miles/hour (mi/hr or mph)
	0.01667	meters/second (m/sec)
	1.6670	centimeters/second (cm/sec)
	0.06	kilometers/hour (km/hr or kph)
Meters/second (m/sec)	2.2369	miles/hour (mi/hr or mph)
	196.85	feet/minute (ft/min)
	3.28	feet/second (ft/sec)
	100	centimeters/second (cm/sec)
	60	meters/minute (m/min)
	0.060	kilometers/hour (km/hr or kph)

(continued on next page)

Multiply	By	To obtain
Microns	0.0010	millimeters (mm)
	0.0001	centimeters (cm)
	0.00003937	inches (in)
Miles, statute (mi)	160,934	centimeters (cm)
	1609.34	meters (m)
	1.6093	kilometers (km)
	63,360	inches (in)
	5,280	feet (ft)
	1,760	yards (yd)
Miles, nautical	6,080.27	feet (ft)
	1.1516	statute miles (mi)
	1,853.27	meters (m)
	1.8533	kilometers (km)
Milliliters (mL)	0.0010	liters (L)
Millimeters (mm)	0.0010	meters (m)
	0.10	centimeters (cm)
	0.0394	inches (in)
Ounces (oz, avoirdupois)	0.0625	pounds (lb)
	28.3495	grams (g)
	0.0283	kilograms (kg)
Pounds (lb)	16	ounces (oz, avoirdupois)
	0.0005	short tons
	453.6	grams (g)
	0.4536	kilograms (kg)

(continued on next page)

Multiply	By	To obtain
Pounds/barrel (lb/bbl)	0.047	grams/cubic inch (g/in^3)
	2.853	kilograms/cubic meter (kg/m^3)
	0.1781	pounds/cubic foot (lb/ft^3)
	0.0238	pounds/gallon (lb/gal)
Pounds/cubic foot (lb/ft^3)	0.0160	grams/cubic centimeter (g/cm^3)
	16.0185	kilograms/cubic meter (kg/m^3)
	0.1337	pounds/gallon (lb/gal)
	5.6146	pounds/barrel (lb/bbl)
Pounds/gallon (lb/gal)	0.1198	grams/cubic centimeter (g/cm^3)
	119.8260	kilograms/cubic meter (kg/m^3)
	0.0238	pounds/barrel (lb/bbl)
	7.4805	pounds/cubic foot (lb/ft^3)
Pounds/square inch (lb/in^2) (psi)	0.0680	atmospheres
	0.0689	bars
	0.0703	kilograms/square centimeter (kg/cm^2)
	6.89	kilopascals
Pounds/square inch/foot (lb/in^2/ft)	22.6203	kilopascals/meter
Square centimeters (cm^2)	0.1550	square inches (in^2)

(continued on next page)

Multiply	By	To obtain
Square feet (ft^2)	929.03	square centimeters (cm^2)
	0.0929	square meters (m^2)
	144	square inches (in^2)
	0.1111	square yards (yd^2)
Square inches (in^2)	645.16	square millimeters (mm^2)
	6.4516	square centimeters (cm^2)
Square kilometers (km^2)	0.3861	square miles (mi^2)
	100	hectares
Square meters (m^2)	10.76	square feet (ft^2)
Square miles (mi^2)	2.59	square kilometers (km^2)
	640	acres
	259	hectares
Tons, long	2,240	pounds (lb)
	1,016	kilograms (kg)
	1.016	metric tons
Tons, metric	2,204	pounds (lb)
	1,000	kilograms (kg)
	0.9842	long tons
	1.1023	short tons
Tons, short	2,000	pounds (lb)
	907.18	kilograms (kg)
	0.9072	metric tons

CHAPTER 15

Troubleshooting

The Complete Fluids Company

Contents

Overview

This chapter contains troubleshooting tables for the following fluids:

- Completion/workover fluids
- Foam/aerated drilling fluids
- Oil-based muds
- Synthetics
- Water-based muds

The tables include a list of contaminants or operational problems, as well as indications of and treatments for the contaminants or operational problems.

Completion/workover fluids

Completion/workover fluids—Contaminants		
Contaminant	**Indications**	**Treatments**
Dilution from water or lower-density brine	• Loss in density	• Identify source of influx. • Add a compatible solid salt to the brine. • Blend the brine with a compatible, higher-density (spiking) brine. *Note: Blending brine is usually more cost effective than adding salt to brine.*
Iron	• Change in brine color to chartreuse, green, green-brown, or rust-red • Iron content of brine exceeds the operator's specified limit	• For monovalent brines, raise pH by adding caustic soda or caustic potash and filter. • Displace brine with uncontaminated brine and return it to stock point for chemical treatment and filtration.
Solids	• Loss of brine clarity/ increase in turbidity • Particles suspend in or settle out of brine	• Filter brine using plate and frame unit. As an option, filter brine using 2 angstrom pore-size cartridge unit. • Treat brine with VERSAFLOC M341 or VERSAFLOC M441 to facilitate the filtration process.

Foam/aerated drilling fluids

Foam/aerated drilling fluids—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Inadequate hole cleaning	• Fill on trips/connections • Increase in torque and drag • Sporadic returns	• Adjust the volume of injected air.
Influx of formation water (air drilling)	• Water present at the return (blooey) line	• Increase the rate of air injection. • Convert to foam or mist drilling.

Oil-based muds

Oil-based muds—Contaminants

Contaminant	Indications	Treatments
Acid gas	• Depletion of alkalinity	• Increase mud density if possible. • Add lime. • Add NO-SULF H_2S scavenger.
Salt	• Salt crystals on the shaker and in the mud • Drop in electrical stability • Increase in chloride content in water phase	• Add water to dissolve the salt, then add primary/secondary emulsifier, and lime. • Add new mud containing no salt.
Solids	• Increase in solids (retort analysis) • Increase in plastic viscosity • Decrease in electrical stability	• Reduce shaker screen size. • Optimize mud cleaner/centrifuge use. • Dilute mud with oil and maintain density with weight material. • Use optimum solids control.
Water	• Change in mud weight • Change in O/W ratio • Water in HTHP filtrate • Increase in funnel viscosity • Decrease in electrical stability • Increase in mud volume	• Add oil, primary/secondary emulsifier, DRILTREAT, and weight material.
Formation hydrocarbons	• Decrease in mud weight • Increase in oil/water ratio • Increase in HTHP filtrate • Change in luminescence fingerprint	• Add emulsifier. • Add water and salt. • Add weight material.

Oil-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Emulsion breaking	• Water in HTHP filtrate • Low electrical stability • Water-wet solids	• Add primary/secondary emulsifier, or DRILTREAT. • Add DURATONE HT. • Add lime.
High yield point and gel strengths	• Excess organophilic additives • Solids build-up • Water-wet solids	• Add OMC. • Use optimum solids control. • Dilute with oil. • Add emulsifier.
Hole instability	• Cavings • Shale slivers on shaker • Excessive torque and drag	• Adjust water phase salinity. • Add DURATONE HT/BARABLOK to reduce filtrate. • Add primary/secondary emulsifier to tighten the emulsion. • Consider increase in mud density.
Inadequate hole cleaning/ suspension	• Increase in torque and drag • Inadequate gel strengths • Residue in cup • Few cuttings on shaker • Fill on trips/connections	• Add GELTONE II/V SUSPENTONE, or RM-63.
Insoluble salt	• Low electrical stability • Water in HTHP filtrate	• Add water to solubilize salt.
Lost circulation	• Whole mud losses • Decrease in pit volume • Drop in circulating pressures	• Use a GELTONE II/V squeeze or a high-solids squeeze when there is major mud loss. • Add MICATEX lost-circulation material, WALL-NUT seepage-loss control, BAROFIBRE seepage-loss control, or calcium carbonate when there is minor mud loss. *Note: Do not add cellophane or BARO-SEAL lost-circulation material.*

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Oil-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Water wetting	• Mud appears dull/grainy • Large barite flocs • Aggregation of solids • Settling in cup • Over-saturation with calcium chloride	• Add oil. • Add secondary emulsifier, DRILTREAT, or primary emulsifier. • Dilute mud with fresh mud. • Adjust the shaker screen to remove aggregated solids. • Add water to solubilize excess salt.
Weight material settling	• Weight material settles in the viscometer cup • Mud weight varies when circulating after trips	• Add GELTONE II/V SUSPENTONE, X-VIS, or RM-63.

Synthetics

Synthetics—Contaminants		
Contaminant	**Indications**	**Treatments**
Acid gas	• Depletion of alkalinity	• Increase mud density if possible. • Add lime. • Add NO-SULF H_2S scavenger.
Formation hydrocarbons	• Decrease in mud weight • Increase in oil/water ratio • Increase in HTHP filtrate • Change in luminescence fingerprint	• Add emulsifier. • Add water and salt. • Add weight material.
Salt	• Salt crystals on the shaker and in the mud • Drop in electrical stability • High chloride content in water phase	• Add water to dissolve the salt, then add primary/secondary emulsifier. • Add new mud containing no salt.
Solids	• Increase in solids (retort analysis) • Increase in plastic viscosity • Decrease in electrical stability	• Reduce shaker-screen size. • Optimize mud cleaner/centrifuge use. • Dilute with base fluids. • Add weight material. • Use optimum solids control.
Water	• Drop in mud weight • Change in S/W ratio • Water in HTHP filtrate • Increase in funnel and plastic viscosity • Decrease in electrical stability	• Add base fluids, primary/secondary emulsifier, and weight material.

Synthetics—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Emulsion breaking	• Water in HTHP filtrate • Low electrical stability • Water-wet solids	• Emulsifier or DRILTREAT. • Add DURATONE HT/BARABLOK.
High yield point and gel strengths	• Excess organophilic additives • Solids build-up • Water-wet solids • Low S/W ratio for mud weight	• Add OMC 42, OMC 2, or LE THIN • Use optimum solids control. • Dilute with base fluids. • Add emulsifier.
Hole instability	• Cavings • Shale slivers on shaker • Excessive torque and drag	• Adjust water phase salinity. • Add DURATONE HT/BARABLOK to reduce filtrate. • Add primary/secondary emulsifier to tighten the emulsion. • Consider increase in mud density.
Inadequate hole cleaning/ suspension	• Increased torque and drag • Inadequate gel strengths • Residue in cup • Few cuttings on shaker • Fill on trips/connections	• Add GELTONE II/V SUSPENTONE, or RM-63. • Test yield point and gel strengths at elevated temperature. • Increase low-shear rate viscosity with X-VIS and GELTONE II/V • Consider raising S/W ratio.
Insoluble salt	• Low electrical stability • Water in HTHP filtrate • Increase in funnel viscosity and water-wet solids	• Add water to solubilize salt.

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Synthetics—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Lost circulation	• Whole mud losses • Decrease in pit volume • Drop in circulating pressures	• Use a GELTONE II/V squeeze or a high-solids squeeze when there is major mud loss. • Add MICATEX lost-circulation material or BARACARB when there is minor mud loss. *Note: Do not add cellophane or BARO-SEAL lost-circulation material.*
Water wetting	• Mud appears dull/grainy • Large barite flocs • Aggregation of solids • Settling in cup • Over saturation with calcium chloride	• Add base fluids. • Add primary/secondary emulsifier or DRILTREAT. • Dilute mud with fresh mud. • Adjust the shaker screen to remove aggregated solids. • Add water to solubilize excess salt.
Weight material settling	• Weight material settles in the viscometer cup • Mud weight varies when circulating after trips	• Add GELTONE II/V SUSPENTONE, or RM-63.

Water-based muds

Note: This table provides generalized treatments for water-based mud contaminants. For treatments specific to certain water-based muds, see the chapter titled Water-based muds.

Water-based muds—Contaminants		
Contaminant	**Indications**	**Treatments**
Carbonates/ carbon dioxide (CO_2)	• Presence of bicarbonates and carbonates • Increase in rheological and filtration properties • Increase in the spread between P_f and M_f • High and progressive gel strengths (ash gels)	• Treat the mud with lime or gyp. *Note: Increase the mud weight if there is an influx of carbon dioxide.*
Cement	• Increase in rheological and filtration properties • Increase in calcium concentration • Increase in pH	• Add soda ash or sodium bicarbonate. • Optimize solids control equipment. • Treat with thinners if appropriate. • Convert to a system that tolerates high cement levels (i.e., POLYNOX) when treatments are not sufficient to counter indications.
Gypsum/ anhydrite	• Increase in calcium concentration • Increase in rheological and filtration properties • Thick/spongy filter cake	• Treat with soda ash to maintain acceptable calcium levels. • Convert to a system that tolerates high calcium levels when treatments are not sufficient to counter indications.

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Water-based muds—Contaminants

Contaminant	Indications	Treatments
Hydrogen sulfide (H_2S)	• Increase in rheological and filtration properties • Decrease in pH • Presence of hydrogen sulfide, as indicated by the sulfide indicator test and the Garrett Gas Train • Rotten-egg odor	• Treat the mud with hydrogen sulfide scavengers. • Adjust the pH with caustic soda.
Low-gravity solids	• Increase in rheological and filtration properties • Increase in bentonite content as determined by MBT • Increase in low-gravity solids content	• Optimize solids control equipment. • Dilute with base fluid.
Salt formations	• Rapid increase in chloride concentration • Increase in mud weight • Rapid decrease in alkalinity • Increase in filtrate • Thicker/spongy filter cake • Increase in or inversion of rheological properties	• Convert to a saturated saltwater system or displace to an oil-based mud system or synthetic systems when treatments are not sufficient to counter indications.
Saltwater flow	• Increase in pit volume • Increase in chloride concentration • Change in mud density • Decrease in alkalinity • Decrease in MBC • Increase in filtrate • Thicker/spongy filter cake • Increase in or inversion of rheological properties • Well flows with pumps shut off	• Increase density to control the water flow.

Water-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Air entrapment	• Decrease in mud weight • Air bubbles encapsulated in mud • Increase in plastic viscosity • Hammering of pumps	• Thin fluid with chemical treatment or water. • Minimize surface air entrapment.
Bacterial degradation	• Decreasing hydroxyl alkalinity • Increasing carbonate alkalinity • Increase in filtration and rheological properties	• Add biocide. • Add lime. • Treat with fluid loss additive if required. • Treat with rheological control agents if required.
Bit balling	• Reduced drilling progress • Balled bit and string • Swabbing on trips • Packed bits that show little wear	• Maintain appropriate viscosity and gel strengths to keep drilling assembly clean. • Optimize hydraulics.
Corrosion	• External and/or internal pitting on drillpipe • Drillpipe failure • Washouts	• Raise pH to between 11 and 11.5 if possible. *Note: Lime may be used in some applications.* • Add a compatible Baroid corrosion inhibitor.

(continued on next page)

Water-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Differential sticking	• Partial or full circulation • String against porous zone • No keyseats • High fluid loss in muds with a high solids content • Cannot rotate or reciprocate drillpipe	• Cover drillstring at the stuck zone with a Baroid spotting fluid, keeping some in the pipe to move at 10-minute intervals. • Use stretch equation to help locate stuck region. • Reduce mud weight where possible. • Lower HTHP filtrate to minimize cake build-up.
Foaming	• Decrease in mud weight • Foam on surface of mud pits • Decrease in pump pressure • Hammering of pumps	• Add a Baroid defoamer to the mud. • Spray water on the pits. • Add AQUAGEL to salt or low-solid muds.
Gas influx	• Increase in pit volume • Appearance of gas-cut mud • Well does not flow after shutting down pump • Decrease in mud weight at flow line	• Increase mud weight. • Operate degasser.
Gas kick	• Increase in pit volume • Well flows after shutting down pump	• Shut-in well. • Follow proper kill procedures.
Keyseating	• Can rotate but cannot reciprocate drillpipe more than one joint • Partial or full returns • Well is dog-legged	• Backoff and wipe out key seat.

(continued on next page)

Water-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Lost circulation	• Decrease in pit volume • Loss of returns • Whole mud losses • Decrease in circulating pressures	• Add lost-circulation material or set a soft plug. • Lower the mud weight and the equivalent circulating density when possible. • Set a cement squeeze. • Reduce pump speed.
Mechanical sticking	• Cannot rotate or reciprocate drillpipe • Reduced or no circulation • Packing off	• Backoff and wash over. • Improve hole cleaning.
Plastic salt	• Salt sections undergauge after trips • Tight connections • Stuck pipe	• Increase mud weight. • Spot water pill. • Make regular check trips back through salt. • Decrease mud salinity. • Use water to dissolve salt at stuck point.
Sloughing shale	• Excessive shale slivers at shaker • Tight connections	• Reduce fluid loss. • Increase mud weight if possible. • Convert mud to an inhibitive fluid. • Increase mud viscosity if possible. *Note: If drilling through bentonitic shale, increasing the mud viscosity is not necessary.* • Add BAROTROL or BARABLOK. • Reduce pressure surges. • Reduce drillpipe whipping.

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Water-based muds—Maintenance and operational problems		
Problem	**Indications**	**Treatments**
Thermal instability	• Bottoms up mud has high viscosity and gel strengths • Difficulty in breaking circulation • Difficulty in running tools to the bottom • Decrease in alkalinity • Increase in fluid loss	• Add water and use optimum solids control. • Treat mud with thinners, dispersants, or deflocculants. • Consider conversion to a THERMA-DRIL system. • Add lime if carbonate level is increasing.

CHAPTER 16

Water-based muds

The Complete Fluids Company

Contents

Overview

The following table lists the water-based systems in this chapter and provides a matrix that rates each system according to its applicability in various drilling situations. Systems are identified as:

❍ Good
◗ Better
● Best

Systems	Drilling situations							
	Reactive shales/ gumbo	Deep water drilling	Horizontal drilling	Increased ROP	High density (>16.0) 1.92 sg	Salt beds	High BHT 300°F (149°C)	Deviated wells
BARASILC	●	●	❍	●		❍		❍
CARBONOX/ AKTAFLO-S			❍		●		●	
CARBONOX/ Q-BROXIN	❍		❍	❍	●	❍	❍	❍
K-LIG/KOH	●				❍	❍	❍	
Low pH ENVIROTHIN	◗				◗		❍	❍
EZ-MUD	●	●	◗	●		◗		◗
THERMA-DRIL	❍	❍		◗	●	●	●	
PAC/DEXTRID	●	◗	●	●	◗	◗		◗
CAT-I	●	●		●		●		
POLYNOX	●		❍	❍	●		◗	◗
Saturated salt	◗	❍				●		❍

Table 16-1: Water-based systems versus drilling situations. This table rates water-based systems as good, better, or best under various drilling situations.

Water-based Mud Systems

BARASILC

Formulation

The following table provides guidelines for formulating BARASILC systems. This system is formulated in fresh water or monovalent brines.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Soda ash	Calcium remover	As needed
Caustic soda/ Caustic potash	Alkalinity source	As needed
BARASIL-S	Formation stabilizer	40-80 (114-228)
DEXTRID	Fluid loss control agent	2-8 (6-23)
PAC	Fluid loss control agent	0.5-4 (1.4-11)
FILTER-CHEK	Fluid loss control agent	2-8 (6-23)
BARAZAN PLUS	Viscosifier	0.2-2.5 (0.6-7)
BAROID	Weighting agent	As needed
*AQUAGEL	Viscosifier/suspending agent	1-10 (3-29)
*GEM GP/CP	ROP Enhanced lubricity	3-5 % by volume
*BARACOR 95	CO_2 scavenger/buffer	0.5-4 (1.4-11)
*BARA-DEFOAM HP	Defoamer	As needed
*BARASCAV D	Oxygen scavenger	0.2-1 (0.6-3)

Table 16-2: BARASILC product guidelines. This table lists products and provides typical product concentrations for formulating a BARASILC system.

Formulation guidelines

- Treat out hardness in base fluid with soda ash before addition of polymers or BARASIL-S. Base fluid pH should be between 9.5 and 10.
- Ensure that all lines and tanks are clean and free of divalent cation brines or mud before mixing brines.
- Shear polymers throughly to obtain optimum yield.

Caution: BARASIL-S is an alkali solution which can cause burns to the skin and eyes. Wear appropriate protective gear and avoid breathing mists of the solution when working with BARASIL-S. The active mud should be handled as any high pH water based mud system.

Maintenance guidelines

- Silicate depletion rates can be high. Cement, gypsum, anhydrite, lime, formation surfaces, acid gases, and formation water (containing divalent cations) can severely deplete silicate levels.
- Normal operating pH range for BARASILC systems is between 11.5 and 12.5. If pH falls below 11.5, the silicate concentration may be severely depleted. Add BARASIL-S to restore silicate content and pH to appropriate levels.
- The BARASILC system can be thinned through whole mud dilution or with base fluid.
- Nitrogen gas should be used for running HPHT filtration tests, CO_2 gas will cause silicate depletion and give a waxy filtrate.
- Products not listed on the formulation table should not be added to the BARASILC system without prior technical approval.

Note: Maintain SiO_2 concentration at 40,000 to 50,000 mg/L.

Caution: Lubricants or other products containing fatty acid derivatives should not be added to the

BARASILC system. Severe foaming can result. Addition of acidic chemicals should be avoided. Acids will cause silicate depletion and mud gelation.

CARBONOX/ AKTAFLO-S

Formulation

The following table provides guidelines for formulating CARBONOX/AKTAFLO-S systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier/ Filtration control agent	8-20 (23-57)
CARBONOX	Thinner/ Filtration control agent	10-30 (29-86)
*Q-BROXIN	Thinner up to 350°F (177°C)	2-6 (6-17)
Caustic soda	Alkalinity source	2-6 (6-17)
AKTAFLO-S	Surfactant	4-8 (11-23)
BAROID	Weighting agent	As needed
BARO-TROL	Filtration control agent	4-8 (11-23)
*PAC-L *PAC-R	Filtration control agent up to 300°F (149°C)	0.25-1.5 (0.7-4)
*Lime	Alkalinity source	0.25-1.0 (0.7-3)
*BARODENSE	Weighting agent	As needed
*BARANEX	Filtration control agent up to 350°F (177°C)	4-6 (11-17)

Table 16-3: CARBONOX/AKTAFLO-S product guidelines. This table lists products and provides typical product concentrations for formulating a CARBONOX/AKTAFLO-S system.

Maintenance guidelines

- Maintain 1 lb/bbl AKTAFLO-S for every 4 lb/bbl (11.4 kg/m^3) bentonite equivalent.
- Maintain the pH at 9.5 to 10.5 with caustic soda.
- Monitor the alkalinity using P_1/P_2 test. If the hydroxyl alkalinity approaches zero, treat with small quantities of lime to treat out carbonates and increase hydroxyl ion concentrations.

CARBONOX/ Q-BROXIN

Formulation

The following table provides guidelines for formulating CARBONOX/Q-BROXIN systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier/ Filtration control agent	10-35 (29-100)
Q-BROXIN	Thinner/ Filtration control agent up to 350°F (177°C)	4-12 (11-34)
Caustic soda	Alkalinity source	2-6 (6-17)
CARBONOX	Thinner/Filtration control agent	6-20 (17-57)
BAROID	Weighting agent	As needed
*BARAZAN PLUS BARAZAN D PLUS	Viscosifier up to 275°F (135°C)	0.25-1.5 (0.7-4)
*CC-16	Thinner/Filtration control agent	6-12 (17-34)
*Lime	Alkalinity source	0.25-1.0 (0.7-3)
*PAC-R	Filtration control agent	0.25-1.5 (0.7-4)
*PAC-L	Filtration control agent	0.25-1.5 (0.7-4)
*DEXTRID	Filtration control agent	4-6 (11-17)
*BARODENSE	Weighting agent	As needed
*BARANEX	Filtration control agent up to 350°F (177°C)	2-6 (6-17)
*POLYAC	Filtration control agent up to 400°F (204°C)	1-6 (3-17)

Table 16-4: CARBONOX/Q-BROXIN product guidelines. This table lists products and provides typical product concentrations for formulating a CARBONOX/Q-BROXIN system.

Formulation guidelines

- Prehydrate AQUAGEL and AQUAGEL GOLD SEAL before using in seawater/saltwater.
- Treat out the calcium/magnesium.
- Add chemicals through the hopper.

Note: Most freshwater or seawater systems can be converted to a CARBONOX/Q-BROXIN system.

Maintenance guidelines

- Increase the pH of makeup water to between 10.5 and 11.0 to precipitate the magnesium.
- Add soda ash to treat out the calcium.
- Add bentonite.
- Add Q-BROXIN.
- Add caustic soda to maintain a pH of 9-12.0.
- Add filtration control additives and supplemental viscosifiers.
- Monitor the alkalinity using P_1/P_2 test. If the hydroxyl alkalinity approaches zero, treat with small quantities of lime to treat out carbonates and increase hydroxyl ion concentrations.

CAT-I

Formulation

The following table provides guidelines for formulating CAT-I systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
CAT-GEL	Filter-cake base	8-12 (23-34)
BARACAT	Inhibition Filtration control agent	3-6 (9-17)
CAT-HI	Viscosifier	0.25-0.5 (0.7-1.4)
CAT-LO	Viscosifier Filtration control agent	0.75-3.0 (2.1-9)
BARA-DEFOAM 1 BARABRINE DEFOAM	Defoamer	0.05 (0.15) 0.05 (0.15)
CAT-300	Filtration control agent	1.5-6.0 (4-17)
Caustic soda	Alkalinity source	0.25 -1.0 (0.71-3)
BAROID	Weighting agent	As needed
CAT-VIS	Viscosifier	0.25-0.75 (0.7-2.1)
ALDACIDE G	Microbiocide	0.02-0.04 gal (0.52-1.05)
*BARASCAV D	Oxygen scavenger	0.1-0.5 (0.3-1.4)

Table 16-5: CAT-I product guidelines. This table lists products and provides typical product concentrations for formulating a CAT-I system.

Maintenance guidelines

- Maintain the BARACAT concentration at 1 to 4 lb/bbl (3 to 11 kg/m^3) in the mud filtrate.

  Note: Monitor the BARACAT concentration regularly at the suction and flowline using the Baroid BARACAT colorimetric method.

- Add CAT-GEL for improved filter-cake quality.
- Use BARASCAV, when necessary, to combat the effects of a low pH and a high salinity environment. Treat the mud to maintain a sulfite residual of between 80 and 100 mg/L.

Caution: Do not add anionic materials (e.g., lignosulfonate or PAC).

EZ-MUD

Formulation

The following table provides guidelines for formulating EZ-MUD systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Caustic soda/ Caustic potash	Alkalinity source (pH 9-10)	0.1-1.5 (0.3-4)
Soda ash	Calcium remover	As needed
AQUAGEL	Viscosifier Suspension agent	5-17.5 (14-50.0)
EZ-MUD EZ-MUD DP	Shale stabilizer	0.5-3 (1.4-9) 0.2-1 (0.6-3)
CELLEX	Fluid loss control agent	0.2-3.5 (0.6-10.0)
PAC	Fluid loss control agent	0.2-3.5 (0.6-10.0)
BAROID	Weighting agent	As needed
BARAZAN PLUS	Viscosifier	0.1-1.0 (0.3-3)
*DEXTRID	Fluid loss control agent	As needed
*BARO-TROL	Fluid loss control agent	As needed
*FILTER-CHEK	Fluid loss control agent	As needed
*ALDACIDE G	Biocide	As needed
*THERMA-THIN	Deflocculant	0.2-3.0 (0.6-9)

Table 16-6: EZ-MUD product guidelines. This table lists products and provides typical product concentrations for formulating a EZ-MUD system.

Note: The base fluid can be fresh water, sea water, or brine. Add salt (as required) to increase salinity.

Formulation guidelines

- Treat out hardness with soda ash and caustic soda being careful not to increase the pH above 10.
- Prehydrate AQUAGEL and AQUAGEL GOLD SEAL before using.
- Add EZ-MUD slowly through the hopper.
- A special shearing device may be helpful.

  Note: A viscosity hump will occur when the EZ-MUD is added. With shear, the viscosity should decrease as the system becomes deflocculated.

  Note: To obtain the same polymer concentration, use 1/3 as much EZ-MUD DP as liquid EZ-MUD.

Breakover guidelines

Most low-solids, nondispersed systems with a low-to-moderate pH range can be converted to an EZ-MUD system. To convert, follow these steps.

1. Check the mud's pH, hardness, MBT volume, and low-gravity solids content and adjust the mud, if necessary.

   Note: The higher the solids and MBT levels, the longer and more severe the breakover hump will be.

2. Add the recommended concentration of EZ-MUD.

   Caution: Extreme flocculation of the mud may occur, resulting in water separation. DO NOT add deflocculants at this time. The condition will subside after the EZ-MUD has been sheared.

3. Add CELLEX, PAC-R, or PAC-L, as required, for filtration control.

   Note: The system may become thin after adding a filtration control agent.

4. Add BAROID to increase mud weight, as required.

Maintenance guidelines

- Maintain approximately 0.5 lb/bbl (1.5 kg/m^3) of excess EZ-MUD in the filtrate as determined using the PHPA test.
- The pH should not exceed 10.
- Maintain a total hardness of less than 200 mg/L for maximum EZ-MUD stability.
- Presolubilize all caustic materials and add them slowly to the active system. This will prevent the system from getting pH hot spots.
- Use citric acid treatments to lower the pH, when necessary. Other weak acids can be used to lower pH elevated by cement contamination.
- If ammonia odor is detected while drilling cement, assume EZ-MUD content is zero.

Gyp/Q-BROXIN

Formulation

The following table provides guidelines for formulating Gyp/Q-BROXIN systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier/ Filter cake	10-20 (30-57)
Q-BROXIN	Deflocculant/ Fluid loss control agent	4-12 (11-34)
CARBONOX	Fluid loss control agent	4-20 (11-57)
Caustic soda	Alkalinity source	0.25-3.0 (0.7-9)
Gypsum	Calcium source	4-10 (11-29)
PAC	Fluid loss control agent	0.1-2.0 (0.3-6)
*BARANEX	Fluid loss control agent	2-8 (6-23)
*BARO-TROL	Fluid loss control agent	4-8 (11-23)
BAROID	Weighting agent	As needed

Table 16-7: Gyp/Q-BROXIN product guidelines. This table lists products and provides typical product concentrations for formulating a Gyp/Q-BROXIN system.

Formulation guidelines

- Prehydrate AQUAGEL.
- Ensure that Q-BROXIN is added before caustic soda to prevent the flocculation of bentonite.

Breakover guidelines

To convert an existing system to a Gyp/Q-BROXIN system, follow these steps.

1. Dilute the mud to reduce the bentonite equivalent (MBC) to less than 15 lb/bbl (42.75 kg/m^3).
2. Add Q-BROXIN.
3. Add caustic soda to adjust the pH to 9.5-10.0.
4. Add gypsum.

   Note: Severe flocculation may occur when gypsum is added.
5. Add PAC.
6. Add barite to increase weight as necessary.

Maintenance guidelines

1. Maintain the pH between 9.5 and 10.
2. Maintain calcium levels between 800 and 1400 mg/L.

   Note: Calcium levels in excess of 1600 mg/L adversely affect rheology and HTHP fluid loss.
3. Maintain excess gypsum levels at 2-6 lb/bbl (6-17 kg/m^3).

$$\text{Excess gypsum, lb/bbl} = 0.48 \times [V_m - (V_f \times F_w)]$$

$$\text{Excess gypsum, kg/m}^3 = 1.37 \times [V_m - (V_f \times F_w)]$$

An approximation of excess gypsum can be obtained by:

$$\text{Excess gypsum, lb/bbl} = (V_m - V_f)/2$$

$$\text{Excess gypsum, kg/m}^3 = (V_m - V_f) \times 1.5$$

Where

V_f is the versenate endpoint of the filtrate
V_m is the versenate endpoint of the mud
F_w is the water fraction

KOH/K-LIG

Formulation

The following table provides guidelines for formulating KOH/K-LIG systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Prehydrated AQUAGEL	Viscosifier	14-20 (40-57)
Q-BROXIN	Deflocculant	2-6 (6-17)
Caustic Potash	Alkalinity and potassium source	0.5-1.5 (1.4-4)
K-LIG	Potassium source/ Filtration control agent	2.0-10.0 (6-29)
BARAZAN D PLUS	Low shear-rate viscosifier	0.25-0.5 (0.7-1.5)
BAROID	Weighting agent	As needed
*Potassium acetate	Potassium source	0.5-1.0 (1.4-3) *Note: Potassium acetate is also compatible in this system in a seawater 15-20,000 ppm Cl^- environment.*
*CELLEX	Filtration control agent	0.5-2.0 (1.4-6)
*DEXTRID	Filtration control agent	0.5-3.0 (1.4-9)
*PAC	Filtration control agent	0.5-2.0 (1.4-6)

Table 16-8: KOH/K-LIG product guidelines. This table lists products and provides typical product concentrations for formulating a KOH/K-LIG system.

Low-pH ENVIRO-THIN

Formulation

The following table provides guidelines for formulating Low-pH ENVIRO-THIN systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier	15-25 (43-71)
ENVIRO-THIN	Deflocculant	2-8 (6-23)
Caustic soda	Alkalinity source	As needed
CARBONOX	Fluid loss control agent	2-10 (6-29)
PAC	Fluid loss control agent	0.5-2.0 (1.4-6.0)
BAROID	Weighting agent	As needed
*EZ-MUD	Shale stabilizer	0.25-0.5 (0.7-1.4)
*BARAZAN PLUS	Viscosifier	0.5 (1.4)
*BARO-TROL	Fluid loss control agent	2-6 (6-17)
*BARASCAV	Oxygen scavenger	0.1-0.2 (0.3-0.6)
*Bicarbonate of soda	Hardness control agent	As needed
*THERMA-THIN	Deflocculant	0.5-1.0 (1.4-3)

Table 16-9: Low-pH ENVIRO-THIN product guidelines. This table lists products and provides typical product concentrations for formulating Low-pH a ENVIRO-THIN system.

Maintenance guidelines

1. Maintain the pH at 8.5-8.8.
2. Prehydrate all AQUAGEL additions in fresh water.
3. Prehydrate CARBONOX and BARO-TROL additions in caustic water that has a pH of 10 or above.
4. Maintain total hardness 200 mg/L as calcium.

Note: Use soda ash to treat out calcium to a level 200 ppm, except for cement contamination when bicarbonate of soda should be used.

PAC/DEXTRID

Formulation

The following table provides guidelines for formulating PAC/DEXTRID systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier in initial formulation	5-8 (14-23)
DEXTRID	Filtration control agent	4-6 (12-17)
PAC	Filtration control agent	1.5-4.0 (4-12)
Caustic soda/ Caustic potash	Alkalinity source	0.5-1.0 (1.4-3)
BAROID	Weighting agent	As needed
*BARAZAN PLUS	Viscosifier	0.25-1.0 (0.7-3)
*Soda ash	Make-up water hardness reducer	As needed
*KCl/NaCl	Reactive shale inhibitor	As needed
*THERMA-THIN	Deflocculant	As needed
*BARASCAV	Oxygen scavenger	As needed
*Lime	CO_2 scavenger	As needed

Table 16-10: PAC/DEXTRID product guidelines. This table lists products and provides typical product concentrations for formulating a PAC/DEXTRID system.

Formulation guidelines

- Treat out calcium in make-up water with soda ash before adding AQUAGEL.

Maintenance guidelines

- Maintain the MBC at less than 20 lb/bbl (57 kg/m^3) equivalent bentonite content.

POLYNOX

Formulation

The following table provides guidelines for formulating POLYNOX systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
AQUAGEL	Viscosifier	10-25 (29-71)
LIGNOX	Deflocculant	4-8 (12-23)
Caustic soda/ Caustic potash	Alkalinity source	2-6 (6-17)
LIME	Calcium source	4-12 (12-34)
CARBONOX	Deflocculant/ Fluid loss control agent	8-12 (23-34)
DEXTRID IMPERMEX	Fluid loss control agent up to 250°F (121°C)	4-6 (12-17)
BAROID	Weighting agent	As needed
*THERMA-CHEK	Fluid loss control agent	1-2 (3-6)
*BARANEX	Fluid loss control agent up to 350°F (177°C)	4-8 (12-23)
*THERMA-THIN	HT deflocculant	1-4 (3-12)
BARAZAN PLUS/ BARAZAN D PLUS	Viscosifier	As needed

Table 16-11: POLYNOX product guidelines. This table lists products and provides typical product concentrations for formulating a POLYNOX system.

Breakover guidelines

To convert any existing system to a POLYNOX system, follow these steps.

1. Dilute the mud as needed to obtain a bentonite content of 15 lb/bbl (43 kg/m^3) or less.
2. Add LIGNOX and caustic (pH 11.5) on the first circulation.
3. Add the lime on the second circulation.

Maintenance guidelines

- Maintain the pH above 12.
- Use caustic soda to maintain the P_f between 3 and 4.5 mL of N/50 sulfuric acid.
- Maintain the P_m value of the mud at 14 or greater with lime.
- Maintain a minimum of 3 to 4 lb/bbl (9 to 11 kg/m^3) of excess lime in the POLYNOX system at all times. In formations containing large amounts of acid gases, add even higher levels of excess lime, when necessary.

  Note: To determine if the POLYNOX is deficient in lime content, perform a pilot test by adding 1 to 2 lb/bbl (3 to 6 kg/m^3) of lime. If the fluid rheological properties increase, then the system is deficient in lime.

- Use BARAZAN PLUS to maintain suspension properties.
- Maintain 3-8 lb/bbl (9-23 kg/m^3) LIGNOX.

$$\text{Excess lime, lb/bbl} = 0.26 \times [P_m - (P_f \times F_w)]$$

$$\text{Excess lime, kg/m}^3 = 0.74 \times [P_m - (P_f \times F_w)]$$

An approximation of excess lime can be obtained by:

$$\text{Excess lime, lb/bbl} = (P_m - P_f)/4$$

$$\text{Excess lime, kg/m}^3 = (P_m - P_f) \times 0.7$$

Where

P_f is the phenolphthalein endpoint of the filtrate
P_m is the phenolphthalein endpoint of the mud
F_w is the water fraction

Saturated salt

Formulation

The following table provides guidelines for formulating saturated salt systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
ZEOGEL	Viscosifier/ Suspension agent	10-20 (29-58)
IMPERMEX	Filtration control agent	4-8 (12-23)
Salt (sodium chloride)	Chloride source	As needed
BAROID	Weighting agent	As needed
*AQUAGEL	Viscosifier	As needed
*DEXTRID	Filtration control agent	4-6 (12-17)
*PAC	Filtration control agent	0.25-0.5 (0.7-1.5)
*BARAZAN PLUS	Viscosifier	0.25-2.0 (0.7-6)
*ALDACIDE G	Biocide	As needed

Table 16-12: Saturated saltwater product guidelines. This table lists products and provides typical product concentrations for formulating a saturated saltwater system.

Breakover guidelines

If the MBC is greater than 10 lb/bbl (29 kg/m^3) equivalent bentonite, dump the system and rebuild. If the MBC is less than 10 lb/bbl (29 kg/m^3), add salt, IMPERMEX, and ZEOGEL.

THERMA-DRIL

Formulation

The following table provides guidelines for formulating THERMA-DRIL systems.

- Products are listed in order of addition.
- Contingency products are denoted by an asterisk (*); they can be used with the primary products to obtain properties needed for specific situations.

Additive	Function	Typical concentrations, lb/bbl (kg/m^3)
Soda ash	Hardness remover	0-0.2 (0-0.6)
AQUAGEL	Viscosifier	5-8 (14-23)
THERMA-THIN	Deflocculant	3-5 (8-14)
Caustic soda	Alkalinity source	As needed
THERMA-CHEK	Fluid loss control agent	4-8 (12-23)
BAROID	Weighting agent	As needed
BARASCAV	Oxygen scavenger	0.25-1 (0.7-2.8)
*THERMA-VIS	Viscosifier	0-1.5 (0-4.3)
*BARACOR 95	CO_2 scavenger	0-0.8 (0-2.3)

Table 16-13: THERMA-DRIL product guidelines. This table lists products and provides typical product concentrations for formulating a THERMA-DRIL system.

Maintenance guidelines

- Do not allow the pH to exceed 10.5 because the THERMA-CHEK will hydrolyze.
- Maintain the bentonite content at less than 10 lb/bbl (29 kg/m^3).

CHAPTER **17**

Well cementing

The Complete Fluids Company

Contents

Overview

The main cementing materials used in oilfield applications are:

- Portland cement, API Classes A, C, H, and G
- Blast furnace slag (BFS)
- Pozzolans (fly ash), ASTM Types C and F

Portland cement is the name used for all cementitious material composed largely of calcium, silica, and aluminum oxides. Blast furnace slag (BFS) is a by-product obtained in the manufacture of pig-iron in a blast furnace. Pozzolans are silica or silica/alumina materials that react with calcium hydroxide (lime) and water to form a stable cement. Pozzolans can be natural or synthetic.

Cementing materials are used in drilling operations to:

- Isolate zones
- Support casing in the borehole
- Protect the casing from collapse, corrosion, and drilling shock
- Plug non-producing wells for abandonment
- Plug a portion of a well for sidetracking

This chapter explains the use of additives to control cementing slurry properties and provides the ideal operational guidelines for each type of additive. Slurry design and applications are provided for lead, tail, and squeeze slurries. Plug design, spacer guidelines, and spacer-volume calculations are also provided.

Cementing additives

Slurries prepared with cementing materials are treated with various additives to modify set time, rheological and filtration properties, and density. These additives are classed as:

- Accelerators
- Retarders
- Fluid-loss control additives
- Extenders
- Free-water control additives
- Weighting agents
- Slag activators
- Dispersants
- Strength retrogression preventers

Accelerators

Accelerators shorten a slurry's set time and allow the slurry to develop necessary compressive strength in a practical time frame. Amounts of various additives used to adjust the set times are given in Table 17-1.

Additive	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOW*	gal/bbl	L/m^3		
$CaCl_2$	<120 (<49)	0.5-4.0	n/a	n/a		x
NaCl	<190 (<88)	1.0-10.0	n/a	n/a		x
KCl	<190 (<88)	1.0-3.0	n/a	n/a		x
Alcohols	<150 (<66)	n/a	0-1.0	0-3	x	x
NaOH	<190 (<88)	as needed	n/a	n/a	x	
Gypsum	<100 (<38)	as needed	n/a	n/a		x
Sodium silicate	<100 (<38)	1.0-3.0	2.0-12.0	6-36		x
* %BWOW = percent by weight of water						

Table 17-1: Accelerating additives. Use these accelerating additives to adjust the set time of cement slurries.

Retarders

Retarders delay a slurry's set time. This delay allows the cement to be placed before hardening occurs. These additives counter the effects of increased temperature on a cement slurry. Table 17-2 gives operational guidelines for retarding additives.

Additive	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m³		
Q-BROXIN	<120 (<49)	0.1-2.0	0.2-8.0	0.6-23	x	x
Calcium lignosulfate	100-160 (38-71)	0.1-2.0	0.2-8.0	0.6-23	x	x
Sodium gluconate	150-200 (66-93)	0.1-1.0	0.05-1.5	0.15-4	x	x
Sodium heptogluconate	150-200 (66-93)	0.1-0.8 gal/bbl	0.1-0.8 gal/bbl	0.3-2.3 gal/bbl	x	x
Sodium citrate	150-230 (66-110)	0.1-1.0	0.025-0.40	0.07-1.1	x	x

* %BWOC = percent by weight of cement

Table 17-2: Retarding additives. Use these additives to delay the cement slurry set time.

Fluid-loss control additives

Excessive losses of water to the formation can prevent cement from hardening correctly. Fluid-loss control additives are used to reduce excessive losses of water to the formation. In addition, these additives:

- Increase viscosity
- Retard the set time
- Control free water in the slurry

Table 17-3 lists the common fluid-loss control additives for cement slurries.

Additive	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m^3		
PAC	<200 (<94)	0.125-1.25	0.25-5.0	0.7-14	x	x
CMC	<175 (<79)	0.125-1.50	0.25-6.0	0.7-17	x	x
HEC	<200 (<94)	0.125-1.75	0.25-7.0	0.7-20	x	x
CMHEC	120-230 (49-110)	0.125-1.00	0.25-4.0	0.7-11	x	x
BARAZAN PLUS	<160 (<71)	0.05-0.40	0.1-1.5	0.3-4	x	x
* %BWOC = percent by weight of cement						

Table 17-3: Fluid-loss control additives. These additives control the amount of water lost to formations.

Extenders

Extenders lighten the density of the slurry for cementing across weak formations. A lighter slurry lowers the hydrostatic pressure and helps prevent formation damage. Table 17-4 gives operational guidelines for extender additives.

Additive	Temp. range, °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m³		
AQUAGEL	200 (94)	0.5-8.0	1.0-32.0	3-91	x	
Fly ash, Pozzolan	n/a	As needed	As needed	As needed	x	
Sodium silicate	250 (121)	1.0-3.0	2.0-12.0	6-34	x	x
* %BWOC = percent by weight of cement						

Table 17-4: Extender additives. Extender additives lower slurry density and help prevent pressure damage to weak formations.

Free-water control additives

Free-water control additives tie up water in light weight or extended slurries. If this water were not controlled, the slurry properties would change as water was absorbed into the surrounding formations. This absorption affects slurry flow and placement. Table 17-5 gives operational guidelines for these additives.

Additive	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m³		
AQUAGEL	200 (94)	0.5-8.0	2.0-32.0	6-91	x	x
Aluminum chlorohydrate	250 (121)	0.01-0.20	0.04-0.75	0.1-2.1	x	x
* %BWOC = percent by weight of cement						

Table 17-5: Free-water control additives. Use these additives to prevent water absorption by formations.

Weighting materials

Weighting materials can be used to increase the density of the cement or slag and help control formation pressures. Three weighting materials are listed in Table 17-6.

Weighting material	Specific gravity
Barite	4.2
Hematite	4.8-5.0
Sand	2.6

Table 17-6: Weighting material. Use weighting material additives to control formation pressures.

Slag activators

Blast-furnace slag (BFS) is a latent hydraulic cement material that does not readily react with water. Because of this, the hydration process for BFS is initiated by either chemical activators or elevated temperatures. Chemical activators are used as needed in different ratios and concentrations, depending on the expected temperatures to be encountered (Table 17-7).

Slag activators	Temperature range, °F (°C)
Caustic soda	<180 (<82)
Soda ash	<180 (<82)
Lime	<180 (<82)
Magnesium hydroxide	150-250 (66-121)
Magnesium carbonate	150-250 (66-121)
Tetrasodium pyrophosphate	>100 (>38)
Sodium acid pyrophosphate	>100 (>38)

Table 17-7: Slag activators. Slag activators are designed to trigger the set process in BFS slurries.

Dispersants

Dispersants reduce slurry viscosity, which is very important for placement and cohesion. Proper dispersion of a slurry results in:

- Enhanced early compressive strength
- Improved fluid-loss control
- Improved free-water control

Table 17-8 gives operational guidelines for dispersants.

Dispersants	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m^3		
Naphthalene sulfonate	<200 (<94)	0.1-2.0	0.2-8.0	0.6-23	x	x
Q-BROXIN	110-200 (43-94)	0.1-2.0	0.2-8.0	0.6-23	x	x
Calcium lignosulfonate	<160 (<71)	0.1-2.0	0.2-8.0	0.6-23	x	x
* %BWOC = percent by weight of cement						

Table 17-8: Dispersants. Dispersants reduce slurry viscosity, which allows better placement and cohesion.

Strength retrogression preventers

Cement and BFS slurries that remain at temperatures above 200°F (94°C) exhibit a reduction of compressive strength over time. This phenomenon, called *strength retrogression*, can be minimized or prevented by adding another source of silica, such as silica flour or silica sand, to the slurry. Silica flour requires more mixing water than silica sand to achieve the same viscosity. Temperature ranges and concentrations are given in Table 17-9.

Strength retrogression preventer	Temp., °F (°C)	Concentration			BFS	Cement
		%BWOC*	lb/bbl	kg/m^3		
Silica flour and silica sand	>200 (>94)	15-50	30-200	86-570	x	x
* %BWOC = percent by weight of cement						

Table 17-9: Strength retrogression preventers. These additives are necessary if the cement (or BFS) will remain in a region where the temperature remains above 200°F (94°C).

Slurry design and applications

Slurries, whether cement or BFS, must be tailored to each different aspect of the drilling operation. Some of the different classifications of slurries include:

- Lead slurry
- Tail slurry
- Squeeze slurry
- Plugs

Lead slurry

A lead slurry is designed to cover a large portion of the annulus, either open hole or inside casing. These slurries are lightweight, extended slurries that do not contribute greatly to the hydrostatic head of the cement column.

Tail slurry

A tail slurry is designed to provide most of the support for the casing or liner being cemented. This slurry is placed over the zone of interest to isolate the zone from contamination. The zone of interest can be a producing formation, a water zone, or some other zone that needs to be closed off. Ideal tail slurry characteristics include:

- High density
- Ability to develop high compressive strength

- Good set time control
- No free water

Fluid-loss control additives may be required for a tail slurry.

Squeeze slurry

Squeeze slurries are designed for remedial, or secondary, cementing. These slurries must have good set-time control, good fluid-loss control, and especially good compressive strength development.

Plugs

Plugs should be designed to meet the requirements of the specific application, whether kick-off plug, lost circulation plug, plug and abandon, etc. Ideally, plugs should have a:

- High compressive strength development to seal the plug zone
- Short set time

Spacers

The three main functions of spacers are to:

- Serve as a barrier between the drilling fluid and the cement slurry, thus eliminating contamination between the two
- Clean the casing and the formation of drilling fluid that could prevent good adhesion
- Act as a wetting agent that wets the casing and the formations

For a spacer to be effective, it must fall within certain guidelines for density and compatibility. The spacer must be more dense than the mud, but not as dense as the cement slurry. The margin should be 1 to 1.5 lb/gal each way. This range allows the spacer to separate the

two fluids (the slurry and the mud) and prevent them from contaminating each other.

The spacer needs to be rheologically compatible with both the mud and the cement. The ideal viscosity of the spacer should fall between the viscosity of the mud and the cement.

Spacer volume calculations

To calculate the volume of spacer required for a specific contact time, use the following equation:

$$V_t = (t_c)(q_d)(5.615)$$

Where

V_t = volume of fluid, cu ft
t_c = required contact time, min
q_d = displacement rate, bbl/min
5.615 = cu ft/bbl

In most cases, a contact time of 10 minutes or more provides excellent mud removal.

CHAPTER

18

Well control

The Complete Fluids Company

Contents

Overview

This section explains kicks, warning signs, and kick control. Shut-in procedures and common kill methods are explained, and the steps to accomplish each are provided. Common kill problems are identified, and the solutions for these problems are given.

Kicks

A kick is an influx of formation fluids into the wellbore. Some of the conditions that can induce a kick are:

- Drilling into an abnormally pressured formation
- Failure to keep the hole full during trips
- Insufficient mud weight
- Lost circulation
- Swab/Surge pressures

Warning signs of a kick include:

- Drilling breaks
- Increase in pit volume
- Increase in mud-return flow rate
- Flow with the mud pumps off
- Pump-pressure decrease and stroke-rate increase
- Drilling reversal
- Hole not taking proper fluid volume during a trip

Controlling a kick

Follow this procedure to control a kick:

1. Pull off bottom.
2. Shut off pumps.
3. Check for flow.
4. Shut-in the well.
5. Record pressures.
6. Kill the well.
7. Verify that the well is dead.

Note: The best indication that a well has been killed is when the choke is open 100 percent and there is no flow.

Shut-in procedures

A shut-in procedure can be either soft or hard. When conducting a soft shut-in the choke is partially to fully open when the annular preventer is closed. When conducting a hard shut-in the choke is fully closed when the annular preventer is closed.

Kill methods

Three basic techniques used to kill a well are:

- Wait-and-weight method
- Driller's method
- Concurrent method

Wait-and-weight method

The most widely used kill method is wait-and-weight. In this method, the well is shut-in, and the surface system is weighted up to the required kill weight. The weighted mud is pumped into the well, and the kick is killed in one complete circulation. This method is also called the engineer's or one-circulation method.

Driller's method

In the second kill method, the influx is pumped out of the wellbore after recording the shut-in pressures and pit volume increase, but before weighting up the drilling fluid. Once the influx has been pumped out of the well, the well is shut-in and the surface mud system is weighted up to the required kill weight. This procedure is also called the two-circulation method.

Concurrent method

The third kill method requires weighting up the surface system while circulating out the influx. Once kill weight has been pumped to the bit, then final circulating pressure is maintained on the drill pipe gauge until the influx is out of the wellbore and kill weight mud is returning at the surface.

Kill sheet. Complete the prerecorded and recorded information sections. Then calculate the kill weight mud and the initial and final circulating pressures. See Figures 18-1 and 18-2 for an example of a kill sheet.

PRE-RECORDED INFORMATION

Pump No.1 Pump No 2

Original Mud Weight (OMW) _____ lb/gal — Surface to Bit ___ bbls ___ stks ___ stks

True Vertical Depth (TVD) _____ ft — Bit to Surface ___ bbls ___ stks ___ stks

Measured Depth (MD) _____ ft — Totals ___ bbls ___ stks ___ stks

Pump No. 1 _____ bbl/stk — Pump No. 2 _____ bbl/stk

KRS _____ spm KRP _____ psi — KRS _____ spm KRP _____ psi

KRS _____ spm KRP _____ psi — KRS _____ spm KRP _____ psi

SHOE: Test _____ lb/gal Depth _____ ft MACP _____ psi Bit to Shoe _____

RECORDED INFORMATION

SIDPP _______ psi SICP _______ psi Pit Gain _______

KILL CALCULATIONS

Kill Weight Mud (KWM) $= \dfrac{\text{SIDPP}}{0.052 \text{ x TVD}}$ + OMW: $\dfrac{(\quad)}{0.052 \; x \; (\quad)} + (\quad) =$ ____

Initial Circulating Pressure (ICP) = SIDPP + KRP: $(\quad) + (\quad) =$ ____ psi

Final Circulating Pressure (FCP) $= \dfrac{\text{KWM}}{\text{OMW}}$ x KRP: $\dfrac{(\quad)}{(\quad)}$ x $(\quad) =$ ____ psi

Figure 18-1: Sample kill sheet. The top half of a kill sheet is a work sheet for necessary kill calculations.

Where

- *OMW* is the original mud weight (lb/gal)
- *TVD* is the true vertical depth (ft)
- *MD* is the measured depth (ft)
- *stks* is strokes
- *spm* is strokes per minute
- *KRS* is the kill rate speed (spm)
- *KRP* is kill rate pressure (psi)
- *MACP* is the maximum allowable casing pressure (psi)
- *SIDPP* is the shut in drill pipe pressure (psi)
- *SICP* is the shut in casing pressure (psi)
- *KWM* is kill weight mud (lb/gal)

PRESSURE SCHEDULE

INITIAL CIRCULATING PRESSURE

FINAL CIRCULATING PRESSURE

Pump Strokes											
Drill Pipe Pressure											

Figure 18-2: Sample kill sheet, continued. Using the values derived from the kill sheet calculations, plan the pressure relief schedule.

Kick control problems

While controlling a kick, some of the problems that can occur include:

- Lost circulation
- Plugged jets
- Washed-out choke
- Plugged choke
- Washout in the drillstring
- Gas migration
- Off-bottom bit
- Gas hydrate formation

These problems can result from the increased pressure and heavy kill-weight mud. In some cases, more than one problem can occur. Use Table 18-1 to determine the source of problems during a kill procedure.

	Indication		
Situation	**Drillpipe pressure**	**Casing pressure**	**Pump rate**
Total circulation loss	Major decrease	Major decrease	Increase
Partial circulation loss	Major decrease	Decrease	Increase
Choke plugging	Major increase	Major increase	Decrease
Jet plugging	Major increase	No change	Decrease
Choke washout	Major decrease	Major decrease	Increase
Drillstring washout	Major decrease	No change	Increase

Table 18-1: Kill procedure problem indicators. Use these guidelines to quickly identify problems in well-control situations.

Solutions for dealing with a lost circulation problem are detailed in the chapter titled *Lost circulation*.

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